**California**. Although it was the first state to move to retail electric competition, California established a market structure and pricing mechanism for Default Service that has not been copied by other states. California=s restructuring statute,[8] enacted in 1996, required incumbent utilities to serve any customer as a default provider and mandated a 10% rate reduction to accompany the move to competition. Actual full scale retail competition began in March 1998. As of that date, utilities were required to sell all the power they owned and buy needed power for Default Service from the Power Exchange utilizing the spot market until the end of the transition period, April 2002, at which time stranded cost recovery was to be completed. A separate organization, the California Independent System Operator (ISO) was given control of the transmission system and required to maintain the safety and reliability of the electric system, as well as the obligation to buy sufficient power to balance the power needs of the system.

The Commission required that utilities pass through the wholesale price of electricity as reflected in the Power Exchange rate to their customers. This rate was calculated weekly based on hourly price changes and so the price for this service varied every month and is subject to more significant variation between the summer and winter months. During the transition period when utilities are collecting stranded costs, this volatility in masked in part by a mandated 10% rate reduction. In other words, no matter what the price of the power bought by the utility from the Power Exchange, the resulting total bill must be 10% lower during the transition period. It was expected by the Commission and the utilities who endorsed the restructuring plan that the cost of power would in fact drop and that the utilities would use the differential between the actual costs and the price billed to customers to pay off their stranded costs.

Universal service and energy efficiency programs were also explicitly approved as part of the move to retail electric competition and the long-standing tradition for including the costs of these programs in the rates paid by all customers was continued. Low income customers are served as part of the residential class in general, but qualified low income customers have access to a 15% rate discount at each electric and natural gas utility through the California Alternative Rates for Energy (CARE) program. This discount is calculated based on the total bill, including energy.

A residential Default Service customer in California[9] receives a monthly bill which states the unbundled energy costs and then breaks down the total electricity charge into the following components:

$ CTC (Competitive Transition Cost) Charge (stranded costs)

$ PX Energy Charge: AThe Average PX charge is based upon the weighted average costs for purchases through the Power exchange. This service is subject to competition. You may purchase electricity from another supplier.@ The customer is informed of this charge on their bill, that is, the average PX charge per kWh during the billing period.

- $ Transmission Charges
- $ Distribution Charges
- $ Nuclear Decommissioning Charges
- $ Public Purpose Program Charges
- $ Trust Transfer Amount (securitization of stranded costs and the mandated rate reduction)
- $ Other Charges

If a customer shops for electricity and selects a competitive provider, the bill will be calculated as if the customer was a bundled service customer and then show a credit for the amount of the PX price for that month. In other words, in order to compete with Default Service, the supplier has to sell generation service at a retail price than is less than the wholesale spot market price passed through by the utility. This exercise is made in even more difficult for the supplier because the utility=s PX charges will vary every month to reflect the market wholesale price, but this volatility is masked by the overall 10% rate reduction. As a result, competitive providers are not able to market the sale of generation in a manner that allows a customer to compare the price of generation that appears on the utility=s monthly bill. No matter what price is stated for PX Energy on the customer=s bill, the total bill will reflect a 10% rate decrease during the transition period. Suppliers would have to offer a product that beat the monthly wholesale price and cannot do so by offering a fixed price or Ahedged@ price because the customer=s bill is held steady no matter how volatile the market operations. The reason why most suppliers early on decided that they could not compete in the residential market in California is not hard to determine in light of this approach.

The legislation intended that the rate reduction would disappear when the utility had paid off its stranded costs. When this occurred, no later than April, 2002, the 10% rate reduction would disappear and the actual monthly PX price adjustment would appear on the customer=s bill. Therefore, if there were no change in the cost of generation in the wholesale market from the initiation of competition in March, 1998 through March 2002, all residential rates would increase at least 10% due to the end of the mandated rate reduction. However, at least one utility paid off its stranded costs earlier than projected. In early 1999, San Diego Gas and Electric obtained PUC approval to end the 10% rate decrease and begin billing that actual PX Energy charge. On an annual basis, both the Commission and the utility expected that customer=s total bill would decrease.[10] However, the potential volatility associated with the expected seasonal increase in the PX wholesale price during the summer months was addressed by putting a cap of 12.5% on the increase associated with any summer electric bill (July, August, September). If the total bill would otherwise increase by more than this amount due to the PX energy prices, SDG&E was authorized to collect the difference from its customers in future bills, thus attempting to levelize the expected modest seasonal volatility in rates.

In fact, the Commission strongly supported the notion of Aaccurate price signals@ in a related decision: A Only through accurate price signals can customers understand how their usage impacts the system and make economically efficient choices. The price of electricity fluctuates;

thus far, consumers have not been impacted by these fluctuations. Consumers should have the opportunity to respond to such market signals as they see fit, which may include shifting load, conserving power, or procuring the commodity through direct access. As the market evolves, we would expect ESPs to offer products and services that will allow greater means to smooth bills.@[11] Of course, all electric utilities were required to continue offering budget payment plans.

These assumptions about annual customer savings were proven wrong when in May 2000, PX energy rates began to increase dramatically. Bills for SDG&E customers increased 200-400% during the summer of 2000. While customers were paying 3.5 cents per kWh for the generation portion of the bill prior to the end of the transition rate reduction, they were facing charges as high as 20 cents per kWh by mid-summer. While SDG&E passed through these high wholesale power prices to their customers, other electric utilities had to pay the same higher costs for this wholesale power, but were unable to pass through these charges to customers because they were still subject to the 10% rate reduction (Southern California Edison, Pacific Gas & Electric). Nonetheless, because of the structure of the California electric market, these utilities had to continue buying power through the PX. Throughout the summer and fall of 2000, the rising wholesale power costs were labeled a Acrisis@ and utilities and state officials sought intervention by the Federal Energy Regulatory Commission (FERC) to establish caps on rates for wholesale power. Average prices in the wholesale market were four to five times the prices of a year earlier, and three to four times the level utility could charge customers. The shortfall for PG&E and SCE was approximately $5 billion by late fall. However, the assumption that the high prices would ameliorate with the onset of winter proved false and the deficits continued to mount.

The California Legislature and the Commission reacted to the SDG&E bills by enacting a rate freeze, retroactive to June 1, 2000. Under this rate freeze, the utility cannot charge a residential customer more than 6.5 cents per kWh for the generation portion of the bill through December 2002, which is still a substantial increase compared to rates charged in 1999. The excess costs incurred by SDG&E are being carried in a balancing account for later rate treatment. In addition, on August 24, 2000, President Clinton released $2.6 million for additional fuel assistance in the San Diego area.

By the end of 2000, both PG&E and SCE were facing junk bond ratings for their securities and the refusal of some generators to sell power to the utilities because of their fear of nonpayment. Public discussion of bankruptcy was widespread. In December, wholesale power rates hit $600 per megawatt hour, compared to $120 in June and $22 at the time deregulation went into effect in March 1998. Power costs for November and December alone, exceeded the total cost for all of 1999 by 28%. In mid- January 2001, rolling blackouts hit the northern part of California, including parts of downtown San Francisco. Southern California Edison announced a workforce reduction of 1,850 jobs in the December, 2000-January, 2001 time period. Reduced expenditures for operations and maintenance were put into place totaling $465 million.

As a result of these financial emergencies, both PG&E and SCE have filed for permission to halt the transition rates and charge higher rates, claiming that stranded cost recovery has been completed early. Both have sought to change their rate design so that customers pay higher flat rate charges for distribution service. In reaction to the financial emergency facing PG&E and SCE, the PUC authorized temporary rate increases for all PG&E and SCE customers, with an average 9% increase for residential customers, effective January 2001.[12] Also, as a short term measure to allow power to keep flowing, the California Legislature authorized the State Department of Water Resources (DWR) to buy electricity on behalf of the utilities. Since January, the State has spent about $50 million per day to buy power for the utility customers and has initiated negotiations to buy power under long term power contracts with generators directly. In early February, the Legislature enacted an even more sweeping measure that guarantees that the State will provide the major role in the purchasing of electricity for many years. Under this legislation[13], the State is authorized to enter into long term power contracts and pay for the energy by means of revenue bonds that will be reflected in all customer bills. As a result, the State DWR will sell power to retail customers and use the utilities to bill and collect on behalf of the State. Meanwhile, the two utilities owe generators $12 billion and have defaulted on payments for power bought several months ago. Neither the Legislature nor the Commission has yet addressed this $12 billion deficit, but Governor Davis has entered into negotiations with the utilities that will focus on the State=s purchase of the transmission system, the payment of which would be used by the utilities to pay for power bought prior to January, 2001 when the State began to purchase power directly for utility customers. Finally, in March 2001, the PUC approved another round of rate increases for SCE and PG&E that are targeted to customers who use 130% or more of their baseline electricity level.[14]

Many observers have identified the key factors that have given rise to this crisis:

$ increased electricity demand;
$ lack of adequate generation supply;
$ a poorly designed market structure (the creation and duties of the ISO and PX are unique to California);
$ the impact of rising natural gas prices throughout the country, thus causing increased costs to operate some generating facilities;
$ manipulation of the market by the generators who bought the plants previously owned by the utilities (Enron, Dynergy, Duke Energy, Reliant Energy, and Southern Company);
$ mismanagement by the utilities who could have obtained fixed price contracts in the fall of 2000 and refused to do so, thus taking their changes with the volatility of the wholesale market; or
$ simply bad luck (i.e., lower rainfall in the Pacific northwest).

These reasons will be the subject of vociferous arguments over the coming months. Unfortunately, the final result is likely to include higher energy charges for customers.

In addition to the adverse impact in California, the volatile wholesale market has had a negative effect on other states, notably Oregon, Washington, and Montana. The adverse impact on Oregon and Washington has occurred even though those states have not adopted retail electric competition because utilities in those states have sought to enter the wholesale market to buy power for their customers and found a power shortage or high prices, reflecting the market needs of California consumers, as well as the rapid growth in demand in their own regions. A number of publicly owned or municipal utilities in the Pacific Northwest have filed for rate increases with their respective state commissions.

The impact in Montana is particularly adverse. Montana adopted retail electric competition in 1997.[15] Larger customers, who had pushed for the legislation, were able to shop for competitively priced electricity before residential customers. Many large industrial and commercial customers entered into contracts for variable priced power. The price charged for electricity took a substantial jump in the summer of 2000, mirroring the California market. Many factories, refineries and mining companies have temporarily shut down or reduced employment as a result of soaring power costs. A recent survey of industrial customers in Montana has revealed that higher electricity prices will force more than half of Montana=s largest manufacturers to make major business changes in the upcoming year. Since the summer, electricity rates in Montana have increased tenfold.[16] As a result of these developments, the onset of retail electric competition for residential customers has been delayed from July 1, 2002 until at least July 2004. This delay, an option given to the Montana PSC in that state=s restructuring legislation, will continue the distribution utility=s obligation to serve and the Commission=s ability to oversee rates for the total electric bill.

As of March 2001, residential customers in California have seen rate increases that vary from about 9% for customers of SCE and PG&E. These rates are now scheduled to increase by 30-40% beginning in May 2001. SDG&E residential customers still pay 6.5 cents per kWh. Most observers have assumed that all customers will see another 10% rate increase at the statutory end of the transition period in April 2002, if not sooner. Further rate increases may also be ordered.

**Pennsylvania.** The Pennsylvania restructuring legislation[17] provides that the local electric distribution utility must serve as the default provider for a minimum of three years, after which the Commission has the authority to establish the method by which the default provider will be selected. The price of Default Service is closely related to the rate caps contained in the legislation. Section 2804 of the Customer Choice Act requires two different rate caps. The first rate cap is on the charges for regulated distribution service and is operative for 54 months or until the Competitive Transition Charge (Stranded Costs) is completed and all customers have choice, whichever is shorter. The other rate cap applies to the generation portion of the utility=s rate and is for nine years or until the CTC is completed and all customers have choice, whichever is shorter. The first rate cap sets a ceiling for all distribution company rates, both for generation services sold to customers by the distribution company and for the distribution/transmission portion of the bill. The second rate cap sets a ceiling only for the generation portion of a utility=s charges to customers who purchase generation from the utility, including stranded cost recovery charges, so that these charges will not exceed Athe generation component charged to the customers that has been approved by the commission for such service, as of the effective date of this chapter,@ i.e., January 1997.

Section 2807(E)(1) of the restructuring Act specifies that an electric distribution company has an obligation to serve, including the obligation to produce or acquire electric energy for its customers, while such utility collects stranded costs or until 100% of its customers have choice, whichever is longer. Section 2807(E)(2) requires the Commission to establish rules that will govern the provider of last resort service after the end of the phase-in period. The legislation specifically authorizes (but does not require) the use of competitive bidding to obtain POLR service after the end of the transition period. Even so, the pricing structure of those future rules must still assure compliance with the rate cap provisions during the period in which stranded costs are being recovered.

In summary, under the Customer Choice Act, the electric distribution company must provide generation services to any customer who is not eligible to choose or who, <u>for any reason</u>, seeks to obtain generation services from a distribution company. During the operation of the rate caps, the price for this generation service cannot exceed the rates for this service in effect on January 1, 1997. Customers who try the competitive market and then return to their distribution company still receive the protections of the rate cap. The only rates that are not applicable to the rate caps are for new services. Utilities may in fact seek to obtain this generation service from other sources, but the total customer bill, in the case of the first rate cap, or the generation portion of the bill (plus the stranded cost recovery charges) in the case of the second rate cap, cannot exceed the rates in effect on January 1, 1997, except for a narrow set of reasons set forth in the Act. These reasons include a petition by a utility that seeks to demonstrate that its financial viability is at significant risk unless the Commission makes a changes in the rates subject to these rate caps. As a result, Pennsylvania=s legislation provides residential customers with a Areal@ rate cap that was intended to prevent customers from being subjected to market prices during the transition period, but would stimulate customers to leave Default Service if competitive providers could structure offers that reduced the price of the generation service or offered additional services to customers.

The statutory rate caps have been extended in numerous settlements of both restructuring proceedings and other proceedings, such as the merger between PECO Energy and Unicom in 2000 and the divestiture of power plants by GPU Energy and Duquesne. Total rates are capped at January 1. 1997 levels until 2005 in many cases and generation rates are capped at set levels until 2010 in most service territories. Furthermore, the restructuring proceedings resulted in settlements that in most cases reduced current rates from 2% to 8%, a result that was not mandated by the Competition Act. This extended transition period was designed to make rates stable for customers so that the wholesale market could develop gradually.

Most important, the Pennsylvania Commission unbundled the utility=s January 1, 1997 rates in a manner that created a default price for generation service (Ashopping credit@) that complied with the statutory rate caps and that was more than the then-expected retail market price of electricity. As a result, competitive suppliers were able to offer retail rates for generation service that were below the Default Service price in most cases and where the spread between these two prices was largest, more competitive shopping and supplier activity has occurred. As of January 1, 2001, 568,492 customers have switched to alternative suppliers, of which 473,852 are residential customers. While the percentage of residential customers that have switched varies by utility, 33% of Duquesne=s residential customers and 16.2% of PECO Energy=s residential customers have switched. PennFuture[18] has estimated that Pennsylvania consumers have saved $2.84 billion since January 1, 1997. At the same time, these restructuring case settlements have resulted in a significant expansion (a fourfold increase in some cases) of low income bill payment assistance and energy assistance programs. In PECO Energy=s service territory, 80,000 low income residential customers are on a discounted rate program funded through distribution rates.

The Commission issued Interim Guidelines for Provider of Last Resort Service (November 19, 1998, Docket No. M-00960890F0017) to govern an electric utility=s obligations pursuant to the Customer Choice Act. These guidelines basically set forth the obligations of the electric distribution utility pursuant to those provisions of the Act already described above. The most controversial aspect of the guidelines was whether the Commission should regulate how the utilities should communicate with its customers about Default Service, some commenters alleging that some utilities were in effect Amarketing@ to customers to urge them not to shop or choose an alternative provider. The Commission stated:

> Since the Commission has a substantial government interest in creating and promoting the formation of a vibrant and effective competitive market for electric generation, some constraints on PLR (Provider of Last Resort) marketing by EDCs are necessary to advance that interest and further the intent of the Act. As an incumbent provider, the EDC possesses an inherent advantage which could be used to undermine competition if unregulated marketing of its PLR role is permitted. In particular, the marketing of the PLR function by EDCs needs to be restrained to avoid anti-competitive conduct so that the objectives of the Act are advanced and fulfilled.
>
> Slip Op. At 14.

This overall policy was then implemented by prohibiting the utilities from using their customer mailing lists to promote the PLR function unless the mailing lists were made available to all other competitive providers for a reasonable fee. The Commission also prohibited utilities from using consumer education funds (recovered from all ratepayers) to promote PLR services and emphasized that it would prohibit any marketing which disparaged competitive providers or implied false facts or made misleading statements. The Commission also reemphasized that utilities may impose no conditions on a customer who receives PLR service or who returns to PLR service. In other words, a utility may not impose any security deposit or other condition of service for a customer returning to PLR service if that customer was previously served by the utility. This policy will prevent the utility from relying on the customer=s payment experience or unpaid debt owed to competitive suppliers in providing PLR service.

In response to the actions of some suppliers who Adumped@ customers onto POLR service when prices in the wholesale market increased in the summer of 2000, the Commission issued an Order[19] which allowed utilities to file tariffs to require commercial and industrial customers to remain with POLR service for a period of 12-months upon a return to this service. However, utilities are not allowed to impose such terms on residential customers.

Finally, the Commission has approved several individual utility restructuring plans and settlements that call for the use of a competitive bid mechanism to select the provider of last resort for some portion of the electric utility=s residential customers prior to the end of the statutory requirement that the utility provide such service. In the GPU Energy, PECO Energy, and Duquesne Light Co. service territories, the utility was obligated to offer at least 20% of their non-shopping residential customers for Default Service by means of a competitive bid. The PECO Energy restructuring settlement provides that on January 1, 2001, 20% of all PECO=s residential customers (to be determined by random selection and specifically including low income and payment troubled customers) will be Aassigned to a provider of last resort-default supplier other than PECO that will be selected on the basis of a Commission-approved energy and capacity market price bidding process.@[20] This service is referred to as Competitive Default Service (CDS).[21] Any bid must comply with the generation rate cap that would otherwise be applicable to PECO Energy. Furthermore, the CDS provider may, at the customer=s option, provide a single bill to the customer which would be issued by the supplier and contain all the regulated utility charges. In doing so the CDS provider must provide all the relevant customer care functions in accordance with the same regulations applicable to electric utilities.

The Commission finalized the guidelines under which the competitive bid process would occur on April 29, 1999 [Docket No. R-00973953, and P-00971265] and established the qualifications for CDS bidders, the process by which the CDS provider will be selected, and the terms and conditions for CDS service. While some commenters sought a bid option in which the supplier could bid for generation supply alone without the customer care (billing and collection) function, the Commission rejected that proposal:

> **The winning CDS bidder will perform customer cares functions, including: billing, credit, advanced meter reading, collections and notices, disputes and disputes resolution, call center activities, switching generation suppliers and EDI/EDEWG transactions. PECO EDC will perform the following customer cares functions: physical termination, restoration of service after a physical termination, maintenance and repair of PECO EDC-owned meters, administration of universal service programs (CAP, LIURP, CARES and Hardship), call center activities related to distribution system outages and emergencies, and discontinuance of service.[22]**

**In addition, the Commission ruled that revenues associated with performing billing and collection in conformance with utility rules, uncollectible expense and universal service costs will be portable with customers assigned to the CDS provider and will be provided to the CDS provider to the extent it is providing these services.**

**In these guidelines the Commission specifically reiterated its long-standing position that no competitive supplier, including the CDS provider, could physically disconnect a customer for nonpayment of competitive charges. A customer may be subject to disconnection for the failure to pay default or PLR service, but this process must conform in every respect to that required for electric utilities and only the electric utility will be allowed access to the customer=s meter to perform this function. Furthermore, the Commission required the CDS provider to submit prices for this service based on the Aexact block rate structure and rate design@ for each customer class. The rates must be fixed for an annual term and the CDS provider must serve all the randomly assigned customers.**

**The Commission refused to adopt a methodology for pricing Default Service proposed by some competitive providers known as the Astranded cost prepayment methodology.@ Pursuant to this approach, a bidder submits a bid which agrees to charge customers the same rates which the electric utility currently charges, but, at the same time, recognizes that there is value in providing that service. In recognition of this value (obtaining a large volume of customers with no marketing or administrative acquisition costs), the bidder bids a lump sum cash payment that it would be willing to pay to obtain the bid. This cash payment was proposed to be applied to the utility=s stranded costs for all residential customers, not just customers receiving the competitive Default Service. The Commission rejected this approach because it would have resulted in higher prices for generation service for those customers served by the CDS provider and the resulting benefit that was proposed to be provided to all residential customers was likely to be small in any case.**

However, the bid process, first initiated by GPU Energy in early 2000 and Duquesne Light later that summer, was unsuccessful in attracting bidders for this service. In the Commission=s approval of PECO Energy=s merger with Unicom in June 2000, however, it accepted a stipulation[23] which made certain changes in the prior restructuring settlement concerning Competitive Default Service. As a result of these changes, PECO Energy was able to negotiate for the provision of POLR service with individual suppliers and eliminate the requirement that the successful bidder assume the customer care function. As a result, the Commission approved[24] an agreement entered into by PECO Energy and New Power Company, Inc. that will become effective April 2001. At that time 20% of PECO=s residential customers who have not yet chosen a competitive supplier will be served by New Power, but PECO Energy will continue to bill and collect the total bill. Customers served by New Power will receive a 1-2% discount off the current PECO shopping credit (price for generation service under the capped rates).

The only cloud on the sunny sky of customer savings and stable Default Service prices has been the petition by GPU Energy to alter its restructuring plan and allow its two electric distribution utilities (Metropolitan Energy and Pennsylvania Electric Co.) to institute a deferral tracking mechanism to reflect higher than expected wholesale energy prices. GPU Energy is one of only two Pennsylvania utilities that elected to divest its generation plants as part of the move to retail competition. Its restructuring settlement also includes provisions to comply with the statutory rate caps and the use of the competitive Default Service bidding procedure. That process did not result in any acceptable bids in early 2000. This petition is likely to be considered in the context of GPU Energy=s petition to merge with First Energy, presently pending before the Commission. On January 19, 2001, the Chairman of the PUC issued a press release which criticized GPU Energy for deliberately alarming consumers and elected officials by suggesting the energy crisis crippling California could easily affect Pennsylvania. The Chairman stated, AI am outraged that GPU would even hint that a similar energy crisis could happen to Pennsylvania. This appears to be a thinly veiled attempt to influence a decision pending before the PUC.@[25]

**Massachusetts:** The Massachusetts restructuring statute[26] creates two services: Standard Offer Service and Default Service.[27] Standard Offer service is provided by existing utilities to all customers who choose not to choose and it is through this vehicle that the statutory mandate for rate reductions (10% in year one and 15% beginning on September 1, 1999) was reflected. Standard Offer service is only available for the transition period of seven years (until March 1, 2005). The Act provides a limited set of circumstances under which a customer may enter the competitive market and then return to this service, but basically new customers who move into a distribution utility=s service territory after competition begins are not able to receive this service, and existing customers may enter the competitive market and return once within 120 days, but such customers are not otherwise eligible for Standard Offer Service. However, pursuant to statute, low income customers (defined as those receiving the low income rate discounts available at each utility) can return to Standard Offer service at any time.

Full retail competition was initiated in March 1998, but very few customers have switched and few alternative suppliers have solicited customers because the regulated Standard Offer Service (SOS) as reflected by the generation charge that appears on unbundled customer bills was priced below the wholesale market price of electricity. Standard Offer rates for residential customers gradually increased, from 3.2 cents per kWh in 1998 to 4.5 cents in 2000 at Boston Edison Co., and from 3.2 cents per kWh to 5.401 cents at Massachusetts Electric. Unlike Pennsylvania, Massachusetts did not unbundle the pre-competition bill in a manner that produced shopping credits that were higher than the current retail electricity prices. Even with the gradual increase in SOS prices, however, the wholesale market saw even higher price increases throughout 2000. As of November 2000, only 2,848 residential customers had switched.

Default Service is available for those customers who move into the service territory after the onset of competition and those who wish to return to regulated service after entering the competitive market. As of late 2000, more than 500,000 residential customers were Aqualified@ for Default Service pricing, primarily because they had moved to a new location since March 1, 1998. Unlike SOS, however, the price for Default Service must not exceed the Amonthly market price for electricity.@ Because it was not clear how this term should be implemented, the Massachusetts Department of Energy and Telecommunications (DTE) decided early on that until the mechanisms for procuring and pricing Default Service could be fully implemented that utilities should provide those eligible for Default Service with the Standard Offer price.[28] However, the DTE initiated a proceeding to implement the market price requirement for Default Service in June 1999.[29] The Department noted that A . . . Default Service pricing and procurement will affect the types and number of bids to supply Default Service and could have implications for the competitiveness of the retail market.@[30] The decision about how to reflect growing market prices for electricity for Default Service customers will eventually affect all customers, even low income customers who are exempt from the Default Service during the transition period. However, after February 2005, Default Service will become the only service that any residential customer can obtain if they are unable to obtain or retain service in the competitive market.

In mid-2000, the DTE decoupled Default Service rates from SOS rates.[31] The Department ordered utilities to offer a fixed-price, six-month Default Service that will be obtained by bids in the wholesale market. Residential customers who must obtain Default Service will be automatically placed on the fixed price rate, but will be offered a month-to-month variable price for this service as well. Commercial and industrial customers will be put on the variable price option. Utilities were ordered to obtain bid prices by customer class, but some utilities stated that they were not able to implement multiple Default Service prices in the current billing systems. The Department rejected a suggestion that the Default Service prices include any administrative costs associated with the procurement of Default Service or other costs, such as bad debt expense. In a later Order[32], the Department clarified that the utility should reconcile the cost for this service annually and that the over- or under-recovery would be passed to all customers. The Department=s objective in its decisions about Default Service was to Asend an efficient price signal.@[33]

The new Default Service rates are effective January 1, 2001. These rates are substantially higher than SOS rates, namely 7.032 cents per kWh at Boston Edison (residential) and more than 8 cents at Fitchburg Gas and Electric and Western Massachusetts Electric Co. While affected customers were issued bill notices to explain the forthcoming rates, bills containing these higher rates were not issued until February 2001.

At the same time that the Department moved to market based rates for Default Service, it was requested by electric utilities in late 2000 to make significant increases in Standard Offer Service as well. The basis for these requests was the rising prices in the wholesale market. In effect, the utilities sought a fuel clause adjustment to their rates and alleged that the Restructuring Act did not intend to prevent such fuel clause adjustments in mandating the 10-15% rate reductions. In a Letter Order issued on December 4, 2000[34], the DTE agreed with the utilities and confirmed that the utilities had been accruing deferred fuel costs and should not continue to do so. As of August 2000, the utilities had accrued standard offer service deferrals of $10 million for Fitchburg, $60 million for Massachusetts Electric, and $144.8 million for NSTAR companies (Boston Edison and two other electric utilities). These accruals were estimated by the utilities to increase substantially throughout 2001. The Commission ordered an annual change in SOS to reflect actual fuel costs incurred by utilities, subject to reconciliation of actual costs incurred to provide this service. Utilities were also ordered to inform customers of these price changes by means of a bill insert.

As a result of this decision, SOS prices increased effective January 1, 2001. The following chart shows the increases in SOS and Default Service prices (cents per kWh) for selected Massachusetts electric utilities for residential customers:

| Utility | 1998BSOS | 1999BSOS | 2000BSOS | 2001BSOS | 2001--Default Service |
|---|---|---|---|---|---|
| Boston Edison | 3.2 | 3.69 | 4.5 | 6.215 | 7.032 |
| Commonwealth Electric | 2.8 | 3.5 | 3.8 | 5.121 | 6.985 |
| Mass. Electric | 3.2 | 3.707 | 3.8 | 5.401 | 6.37 |

In other words, since the onset of restructuring, residential customers on SOS in Boston have seen a 48% increase in the price of the generation portion of the customer=s electricity bill. Newcomers to Boston who must obtain Default Service paid SOS prices in 1998-2000, but beginning in 2001 have seen a 54% increase. These increases have erased the rate cuts that originally accompanied electric restructuring. Mass Electric customers will see the largest increase, about 12% of the <u>total</u> electric bill for a customer who uses 175 kilowatt hours and 17% for 750 kWh usage. The impact of this change on low-income customers has been to erase the effect of the low income rate discount in some cases, or substantially reduce the effectiveness of that discount.

**Maine**: The Maine restructuring legislation[35] has taken the boldest step in the elimination of the current utilities from the retail sale of generation service. Utilities were required to divest[36] their key generation sources and the Standard Offer Service was mandated to be obtained by means of a competitive bid. While utilities are responsible for delivering the Standard Offer to its customers, the generation portion of this service must be obtained in a bid process closely regulated by the Maine PUC. The PUC has promulgated regulations governing this procurement of Standard Offer Service and awarded the first competitive bid for this service effective March 1, 2000, when retail competition began for all customers.

Unlike Massachusetts, Maine has only one Standard Offer and customers are not restricted as to their movement into or out of this service. Furthermore, there are no statutory rate caps or rate reductions applicable in Maine. Therefore, the price for generation service obtained as Standard Offer service will operate as the Aprice to compare@ for customers contemplating a move to the competitive market.

Pursuant to the Commission=s rules,[37] the residential rate for this service must be in a fixed cent per kWh that does not vary by level of usage or time of year or day. Rates must be submitted by bidders for a minimum one-year period. Providers must agree to accept any or all customers in one of three rate classes: residential and small commercial; large commercial; industrial customers. Therefore, all residential customers will remain as a block. If more than one provider is selected, rates will be averaged among the providers for the particular class in question and rates may not vary based on customer location within a specific service territory. The distribution utility will issue a single bill to Standard Offer customers which will show all unbundled charges and prominently display the name of the Standard Offer provider. As part of the responsibility for billing and collecting the total bill, the distribution utility can charge the provider the incremental costs of administering standard offer service, including bill issuance, bill calculation and collection. Each standard offer provider will be allocated a share of the uncollectible accounts in the standard offer class or classes the provider serves in a manner that reflects the provider=s share of sales in the applicable standard offer class. The reasonable costs incurred by the distribution utility in collecting this service, including uncollectible accounts, can be recovered as part of the revenue requirement of the utility. Residential customers cannot be charged a fee to obtain this service unless the Commission determines in a later proceeding that a fee applied to those customers who are frequently switching from competitive to Standard Offer service or vice versa is warranted.

As required by the Maine legislation, a large investor-owned distribution utility may not provide standard offer service except through an affiliate, and the affiliate may submit a bid for only 20% of a standard offer class within its own service territory.

The Maine PUC issued three RFPs on August 2, 1999 for the standard offer service for the three investor-owned utilities, but then rejected the proposals (of which there were only a few) for the two largest utilities on October 25, 1999. A new solicitation ensued with somewhat different bid criteria which allowed bidders to link their Standard Offer bid price offers to the concurrent utility RFP process for the sale of each utility=s generation entitlements to Qualifying Facilities contracts, most of which are classified as renewable energy sources. On December 3, 1999, the Commission selected a successful bidder for the largest utility for the residential and small commercial class at a rate of $0.04089/kWh.[38] This has been widely viewed as a relatively low price which is likely to lessen marketer interest in competing for residential customers. The successful bidder offered this fixed rate for two years which was accepted by the Commission. The Commission did not receive an acceptable bid for other classes and the utility was ordered to obtain the necessary generation service on the wholesale market and provide this service at an administratively determined price.

Other Maine utilities (Bangor Hydro-Electric Co. and Maine Public Service Co.) did not receive bids that were deemed acceptable by the Commission so that those utilities were ordered to go into the wholesale market and obtain power for its Standard Offer customers. Bangor Hydro decided to obtain the necessary electricity by using the spot market and short term contracts. As a result, when the wholesale power rates increased in the summer of 2000 throughout New England, it sought and obtained permissions from the PUC to increase rates significantly for residential (and other) customers. Effective October 1, 2000, residential rates increased to 6.016 cents per kWh, an increase of 32.5% for the generation power of the bill and a 10-12% increase in the total bill. As a result, customers of Bangor Hydro (approximately 30,000 customers) saw their Standard Offer rates increase similarly to those approved in Massachusetts. Commercial customers for all three electric utilities have also seen significant rate increases as a result of their market-based rates. However, residential customers of Maine=s largest electric utility (Central Maine Power) will see stable rates that remain below wholesale market rates until at least March 2002. There are growing concerns about the impact of the wholesale market on commercial customers and the looming impact on all residential customers next year by policymakers. On March 20, 2001, the Senate Majority Leader of the Maine Legislature announced a proposal to form a study commission to analyze the impact of retail electric competition on Maine and its potential impact over the next several years.[39]

**Connecticut:** Connecticut=s restructuring legislation[40] mandates retail competition for all customers by July 2000. The Legislation promised that total rates must be reduced by10% compared to rates in effect on December 31, 1996 and that this rate reduction must remain in effect through the transition period (2000-2003). Similar to Maine, utilities must divest their non-nuclear generation resources in order to collect stranded costs. There is no deadline for the recovery of these costs and, in fact, the DPUC will set the recovery period for this costs to accommodate the legislatively mandated rate reduction for the early years of competition. Rates were reduced at the two largest utilities by 4-5% in anticipation of electric retail competition in 1999. The additional reductions to meet the 10% reduction in the total bill occurred on January 1, 2000. Utilities are obligated to provide Standard Offer Service for the transition period (2000-2003) to any customer who does not shop which must be obtained, in part, by a competitive bid process. Beyond that date, there is no legislative mandate for regulated rates for generation service. Effective January 1, 2000, all customer bills show unbundled rates and a separately stated Generation Service Charge. The Department Public Utility Control (DPUC) recently completed proceedings in which the Standard Offer rate was established for its two largest investor-owned electric utilities.[41]

In its decisions, the DPUC determined that the Generation Service Charge must reflect the retail price to provide energy, that is, the wholesale price plus marketing, personnel, overhead, taxes and profit. The latter group of costs was estimated as $0.005 per kWh to $0.01 per kWh. For United Illuminating residential customers the GSC will be five cents per kWh (4.3 cents per kWh for residential heating customers). This price was approved based on a settlement between the utility and Enron in which Enron offered to provide the Standard Offer service for a four-year period. The GSC rate for Connecticut Light and Power customers was set after CL&P conducted an auction for 50% of its Standard Offer needs (50% will be provided by the utility=s affiliate, Energy Select). In September 1999, the independent bidding agent received eight final bids to provide portions of the approximately 2,000 MW put out to bid. Based on the least cost standard offer bid provided and other contract terms, the CPUC accepted bids from NRG Power Marketing, Inc. and Duke Energy Trading and Marketing Northeast L.L.C. Residential customers will pay a GSC rate of 5.5 cents per kWh. These bids are for a fixed price through 2003 and will not vary by price spikes in the wholesale market. The bids allowed the DPUC to implement the 10% total bill rate reduction.

Unlike the bidding process in Pennsylvania, however, these bids were conducted by the utility in the wholesale market. The winning bidders in Connecticut will not Aget@ the customers nor do the customer bills name the power supplier. Rather the price obtained by the utility for this transition obligation to provide SOS will be passed through on the utility=s unbundled bill and all customers remain with the utility unless the customer selects a competitive provider.

SOS customers in Connecticut can move in and out of this service, but the utility can implement a 12-month stay requirement once a customer=s returns to SOS after entering the competitive market the first time. However, utilities may not impose a switching fee or a higher SOS rate to returning customers.

**New York:** Unlike most other states, New York has implemented retail electric restructuring by means of administrative decisions by the Public Service Commission. There is no statutory mandate for retail electric restructuring. The New York Public Service Commission has issued orders and approved restructuring settlements that have phased in retail electric competition for all customers, but the implementation of restructuring has varied among the different electric utilities. While the Commission has conducted outreach and education, the level of shopping activity by residential customers is relatively low.[42]

In all its restructuring decisions, the Commission required the local electric utility to provide Default Service, referred to as the Provider of Last Resort, at least during the transition period, the term of which varies by individual utility settlements. In most decisions, the settlement resulted in either a rate freezes (e.g., New York State Electric and Gas Co.) or modest rate reductions for residential customers. Unlike other settlements, however, Consolidated Edison proposed to provide Default Service by relying on the wholesale market and passing through this rate on a variable basis every month. At the time of the restructuring settlement, both Con Ed and the Commission portrayed the settlement as one that would result in a 10% rate reduction for customers over the five-year term of the plan.[43] However, the plan allowed for Con Ed to pass through its actual wholesale power fuel costs. This provision has, contrary to the public statements at the time of the plan adoption, resulted in significant rate increases for the generation portion of the bill beginning in the summer of 2000. As of July 2000, Con Ed residential customers were paying 10 cents per kWh for generation alone, far higher than the 4-5 cents paid by residential customers in upstate New York utilities and far higher than the 3.3 cents per kWh paid in 1997. The average monthly bill for residential customers increased from approximately $52 in November 1999 to almost $75 in July 2000 and leveled off at over $60 by late 2000.[44] This has resulted in a total bill rate of over 19 cents per kWh, an increase of about 4 cents per kWh sine 1999.[45] The resulting furor[46] led to investigations that concluded that New York=s wholesale market was flawed and Con Edison publicly warned the Commission that a ACalifornia-type@ situation could result without prompt action from both the New York PSC and FERC. Both the PSC and Con Edison are seeking intervention from FERC to control prices on the wholesale market.[47]

In part due to the experience with market power prices in the summer of 2000, the Commission initiated a major investigation of its competition policies, including the POLR service.[48] The Staff was required to issue a Astrawman@ proposal for POLR service in mid-January.[49] Options being considered by working groups include the gradual elimination of the utility in the provision of commodity services and the use of a competitive bid to obtain POLR service at market-based rates. The Staff=s approach is based on the notion that the utility should ultimately not have any obligation to serve except for regulated delivery or distribution functions and that customers should be expected to enter the competitive market by a date certain and then be Agiven@ to competitive marketers in proportion to the market share obtained by the marketer. Among the many issues being considered in the Working Groups is whether the Commission has the legal authority to order or even approve any utility=s proposal to exit the retail market and become a Awires@ only utility. Briefs have been submitted by the parties, but no decision or ruling from the Commission has yet occurred on this significant issue. However, the comments submitted by the New York Attorney General and the Staff of the PSC suggest that any move to a model in which the utilities seek to exit the obligation to serve would not be possible without a statutory change to the New York Public Service Law.[50]

Also under consideration in this proceeding is whether New York should adopt a comprehensive program to assure reasonably priced electricity for low income customers. While several utilities have agreed to small scale programs to provide bill payment assistance to low income customers, there is no consensus as yet as to any statewide program design or funding mechanism for such programs. The Draft Consensus Report recognizes the need for expanded and coordinated low income bill payment and energy assistance programs, but no funding level has yet been identified. The Report also recognizes that such programs could be funded by means of a nonbypassable charge included in regulated distribution rates.

In addition to its review of the entire electric competition program, the Commission is considering methods to Amitigate@ price spikes for Con Ed customers for the upcoming summer in which a lack of adequate generation supply is likely to result in higher power prices again. While consumers are seeking Ahard@ price caps (equal to 19-20 cents per kWh for the total bill), the Commission=s Staff has proposed temporary rate caps that would merely defer excess prices for later recovery from customers. [51]

At least one other utility, New York State Electric & Gas Corp. (NYSEG), has filed a proposal with the PSC that includes a 7-year price protection plan for its customers. This proposal includes a fixed rate that would be frozen for 7 years with no market pass through based on fuel costs or the operation of the wholesale market.[52] Of course, NYSEG, unlike Con Ed, has not sought to divest its generation facilities.

**Nevada:** Nevada is one of the few states that contemplates that the competitive energy provider (referred to in Nevada as the Aalternative seller@) selected by a customer after the start of retail electric competition will have the sole billing and customer service relationship with the customer. Under this ASingle Retailer Model@ the alternative seller obtains regulated distribution services from the local utility on behalf of the customer and assumes the sole point of contact for billing for all electric services. Such an approach has also been adopted in the Atlanta Gas Light natural gas competition program and in the State of Texas for retail electric restructuring. The basic motivation of the supporters of this approach is to prevent the local utility from maintaining its market share and incumbent provider status. The supporters of this approach also typically oppose allowing the utility to serve as the Default Service provider.

Nevada=s original restructuring legislation[53] required the Commission to designate a Avertically integrated electric utility@ to provide Default Service, but also allowed the Commission to prescribe alternative methods, including direct assignment of customers to competitive providers or the use of competitive bidding to select the Default Service provider. In its first attempt at the implementation of this provision, the Commission proposed a competitive bid process to select the default provider for the start of retail competition with features that were designed to stimulate a Ahigh bid@ approach by competitive providers.[54] Furthermore, the Commission=s original Provider of Last Resort proposed rule called for two Default Services, one for customers who did not choose and one for customers who had a poor credit history or who could not obtain service from an alternative seller. The Commission proposed that the latter group of customers would be identified by the utility based on recent payment history. These credit risk customers would then be moved en masse to what the Commission referred to as AUniversal Last Resort Service.@ The price for Universal Last Resort Service would be based on the costs associated with serving this subset of the residential customer class. Obviously, this customer group is likely to incur more costs relating to payment arrangements, customer service, and bad debt expense, and, as pointed out by the Consumer Advocate in Nevada in comments to the Commission, the price for this service would likely be higher than for other residential customers and so should be opposed as a violation of the statutory rate cap and poor public policy. The Consumer Advocate proposed a single Default Service provider for all customers: AThe single POLR model will assure that the costs of serving the entire customer class will be spread among all customers who benefit from this service, much as the cost of electric service today reflects the average cost to serve each customer class.@[55]

The Legislature halted the Commission=s proposal for the use of a competitive bid and the designation of a Universal Last Resort Service.[56] These amendments also established a new rate cap for each class of customers which expires on March 1, 2003 for POLR customers. The new rate cap was set at a level not to exceed the total rate for each class of customer that was in effect on July 1, 1999. While the rate cap is in effect, the Commission cannot review the rates, earnings, rate base, or rate of return of a designated provider of electric service. In addition, the actual start date for retail competition was pushed back from December 31, 1999 to March 1, 2000, or even later if approved by the Governor.

Subsequent to this legislation, a global settlement was reached on the pending merger between Nevada=s largest investor owned electric utilities and pending lawsuits that had been filed by both utilities challenging restructuring orders of the Commission. Both utilities were allowed to implement a monthly fuel clause adjustment beginning in the fall 2000. This fuel adjustment is allowed to continue while the utility serves as the POLR (through February 2003). However, in part as a reaction to the wild swings in the wholesale market in California, the Governor has further delayed the onset of retail competition Aindefinitely.@

Prior to the Governor=s decision to delay retail electric restructuring, the Governor=s Energy Policy Panel issued a report on January 11, 2001.[57] The report appeared to contain a consensus that some form of low income bill payment assistance and energy conservation and weatherization assistance should be enacted as a condition of implementation of retail competition. However, the report outlined a variety of options for the timing and conditions for the implementation of retail electric competition that revealed a lack of a consensus on key matters. It would appear that retail competition, at least for residential and small commercial customers, will be delayed until there is more certainty concerning the availability of sufficient supply and transmission facilities so as to avoid the rate shocks and volatile markets experienced in California.

**Texas:** The Texas electric restructuring statute was enacted in 1999[58] and calls for the implementation of electric competition for all customers beginning January 1, 2002. The Texas industry model is different than that adopted in most states, but has some similarities to the Nevada approach. Under the Texas approach, customers will obtain electricity service from Aretail electric providers@ or REPs. A REP will have the sole contact and retail relationship with its customers and will obtain the transmission and distribution services on a wholesale basis from the former public utilities. The REP must handle all customer contact and billing for the total electricity service. As of January 1, 2001, all customers will be switched to the affiliate REP of their local electric utility or select an alternative REP. The affiliate REP must provide service to all customers who are transferred to this service under the APrice to Beat@ rate, which will be 6% less than the rates in effect in 1999. In effect, the affiliate REP will provide Default Service under a rate reduction scheme that resembles that in most states. However, customers who are transferred to the affiliate REP will have entered the competitive market, albeit at a regulated rate. The Price to Beat will remain in effect until January 1, 2007 (five years) or until at least 40% of the residential load served by the former electric utility is being served by a non-affiliate REP. Unlike the rate caps in effect in Pennsylvania and several other states, the Price to Beat rate is subject to adjustment based on the cost of fuel at least twice per year. The Commission is finalizing its rulemaking to define the details of the Price to Beat rate, the conditions under which residential and commercial customers can leave and return to this service, and the conditions under which the rate can be adjusted to reflect fuel cost changes.[59]

Customers who do not qualify for the Price to Beat rate or who are terminated by the REP for the failure to pay or maintain service conditions will not be physically disconnected. Rather, such customers will be transferred to the Provider of Last Resort service. It is the POLR service that will provide service to all customers who cannot maintain service in the competitive market after the end of the transition period. This service must be provided by an entity selected by the Commission according to a bidding procedure that is designed to replicate the competitive market. The Commission has issued final rules that govern the bidding process for this service and sought bids according to a Request for Proposals.[60]

Pursuant to the Commission=s rule, the POLR service will provide a basic, standard retail service package to any customer no long served by the customer=s REP or whose REP defaults in its obligations to the distribution utility or other license conditions.[61] The POLR service is viewed as a safety net service, but will also be available to any requesting customer. POLR rates will distinguish between three customer classesBresidential, small commercial, and large commercial customers above 1 MW. The POLR price will be a fixed, non-discountable, seasonally differentiated, firm rate that must be fully hedged or fixed for the time period of the bid, established as a minimum of one year. The POLR service will not include any competitive service offerings, innovative rate structures, or options other than basic, standard rates and service options. The POLR provider has an obligation to serve, but may deny service based on the same criteria applicable to utilities under the Commission=s consumer protection rules. There are no minimum service terms or fees associated with this service, except that a customer that elects a levelized or budget payment plan (which the POLR provider must offer) may be required to agree to a six-month term of service. Only the POLR provider may disconnect service for nonpayment.

Because the bids for this service have not yet been made public, it is not clear how this rate will differ from the Price to Beat that the affiliate REP must offer in the transition period. However, the Commission has retained the right to refuse all bids if they are not Areasonable@ and appoint a REP, including the affiliate REP, to act as the POLR. It is possible, for example, that the Commission would appoint the affiliate REP to act as the POLR provider at the Price to Beat rates during the early years of retail competition. However, in the long run, the POLR price will be based on the development of the electricity market. Furthermore, the POLR service will eventually serve a pool of customers who will not be able to maintain service from a REP or who has been refused service by a REP. This is likely to result in a service that will be somewhat higher than market rates or the Price to Beat. No other state has created a Default Service approach that will isolate payment troubled customers in such a fashion, although the ultimate impact of such an approach will be masked in the early years of the competition program due to the ability of customers to enter and leave the Price to Beat service.

**Ohio:** Ohio also adopted retail electric restructuring in 1999, with an implementation date of January 1, 2001.[62] This legislation retains the utility as the Default Service provider and establishes rate caps for the Amarket development period@ through 2005. Except for certain energy efficiency and universal service riders and the effect of taxation changes, the unbundled rates must not exceed the total bundled rates in effect in 1999. Where the Commission had already approved rate decreases or such decreases were scheduled to go into effect, the restructuring statute preserved and mandates those rate reductions as well. In addition, the generation portion of the bill for residential customers only must reflect a 5% reduction (that will appear on the customer=s bill in the form of a credit) during the transition period. This rate reduction may be altered or removed by the Commission no earlier than 2003 if the Commission finds that it has unduly discouraged market entry by competitors.[63] However, the extent to which the generation rate reduction is in effect has been the subject of negotiations and settlement provisions in the various utility transition plans. The utilities were not required to divest their generation resources. These rate caps are firm and do not include an exception for increased fuel costs. During this period the utility remains obligated to provide Default Service.

Ohio has also legislatively endorsed the PUC=s long standing universal service programs for low income customers. The Percentage of Income Payment Plan (PIPP), in which low income customers are required to pay no more than 15% of their annual household income for electricity and natural gas service, will continue and be integrated with the federal LIHEAP or fuel assistance program administered by the Ohio Department of Development. This program, as well as increased energy efficiency programs, will be funded by Riders that are included in regulated utility rates and paid by all customer classes.

An interesting and unique feature of the Ohio legislation is the emphasis on customer aggregation. Municipalities may adopt an ordinance that aggregates all residents within its boundaries. This aggregation program, if adopted by an ordinance, may use the Aopt out@ method. Under this method, all residents are automatically included in the aggregated group unless they choose not to participate. Residential customers may opt out of the aggregated group every two years without paying a switching fee.[64] A municipality may also use the Aopt in@ method in which the town negotiates a price with a supplier and residents must then sign up with the local government, permitting it to purchase electricity on their behalf. Those who do not provide affirmative permission will remain with the local utility in Default Service or may select another competitive supplier. Ordinances which specify that Aopt out@ method were adopted by hundreds of Ohio communities in the fall of 2000. Subsequently, a consortium of northern Ohio municipalities formed to serve nearly 400,000 customers in the area surrounding Cleveland negotiated a contract with Green Mountain Energy Co. for a six-year supply contract to serve customers in FirstEnergy=s service territory. Service is scheduled to be initiated in September 2001. Such contracts are possible in part due to the restructuring settlement reached for the FirstEnergy proceeding that was approved by the Ohio PUC in which 20% of the utility=s generation was made available to competitors in the early years of competition.[65]

The Default Service obligation under the rate cap provisions do not continue after the market development period, i.e., through 2005. Beginning in 2006, the restructuring legislation requires the distribution utilities to offer a market-based price for this service obtained through competitive bidding. The Commission must adopt rules setting forth this competitive bid process by January 1, 2004[66].

In the Commission=s restructuring rules, customers may be subject to a minimum stay requirement for Default Service. Customers who switch during the summer months will be subject to a 12-month minimum stay provisions, but customers who switch back into Default Service during any other month may do so without restriction. Additionally, residential customers are not subject to any minimum stay requirements during the first year of competition, i.e., calendar year 2001. The Commission has also approved a maximum $5 switching fee.

The Ohio restructuring plan closely resembles the Pennsylvania model in that the incumbent utility retains the Default Service role under capped rates for an extended transition period (although the transition period is longer in Pennsylvania) and shopping credits are calculated so that competitive providers have an incentive to offer services.

## END NOTES

1. Only Georgia has implemented a natural gas competition program for Atlanta Gas Light that requires customers to select a competitive marketer, but this program has not been replicated for electric competition in any state. The experience of the Atlanta Gas Light program has been controversial. See, e.g., Greene, Kelly and Brooks, Rick, AGeorgia=s Gas Deregulation is Messy, but Offers a Lesson to Other States,@ Wall Street Journal, January 15, 2001.

2. This service should be distinguished from a service that is made available to customers who are unable to obtain service in the competitive market because of their credit history or as a result of termination of service by a competitive supplier. Most states have not distinguished the type of service available to these payment troubled customers from that available to any customer who simply does not enter the competitive market, but both Texas and Massachusetts have made certain distinctions in their provision of Default Service that this report will highlight.

3. Pennsylvania Electric Shopping Statistics, January 2001, published quarterly by the Office of Consumer Advocate and available at http://www.paoca.org

4. NEMA, National Guidelines for Restructuring the Electric Generation, Transmission and Distribution Industries, Washington, D.C., January 1999. Also, Press Release, ANational Energy Marketers Association Cites Political as well as Economic Factors for Price Volatility,@ August 8, 2000.

5. NEMA letter to the New York PSC, Case 96-E-0891, March 16, 2001, available on NEMA=s website: http://www.energy marketers.com

6. FERC, Staff Report to the FERC on the Causes of Wholesale Electric Pricing Abnormalities During June 1998, Washington, D.C., September 22, 1998; FERC, NSTar Services Company, Order on Complaint and Conditionally Accepting Market Rule Revisions, FERC, Docket No. EL00-83-000 et al., Washington, D.C. July 26, 2000.

7. In the last several months, the following states have either delayed the adoption of retail electric competition or halted the consideration of proposals to adopt retail electric competition: North Carolina, Iowa, Minnesota, Nevada, New Mexico, Oklahoma, and Montana.

8. AB 1890, eff. September, 1996.

9. This listing and explanation is taken from the residential Southern California Edison bill which appears on its website: http://www.sce.com

10. ACPUC Approves Settlement of SDG&E Changes Once Capital Investment is Paid Off,@ CPUC Press Release, May 27, 1999. See also the SDG&E tariffs and residential bill explanation at its website: http://www.sdge.com

11. California PUC, Final Opinion Regarding Policies Related to Post-Transition Ratemaking, Decision 00-06-034, June 8, 2000.

12. California PUC, Interim Opinion Regarding Emergency Requests for Rate Increases, Decision 01-01-018, January 4, 2001.

13. ABx1, enacted February 1, 2001.

14. San Francisco Chronicle, A70% to Pay Bigger Bills, PG&E Says Firm=s Estimate Higher than PUC Chief=s,@ March 29, 2001, URL: http://www.sfgate.com/cgi-bin/article.cgi?file=/chronicle/archive/2001/03/29/MN90356.DTL

15. Senate Bill 390 (1997), AElectric Utility Industry Restructuring and Customer Choice Act@ (Title 69, Chapter 8, MCA).

16. Dow Jones Newswires, AMontana=s Industries Pinched by High-Flying Power Prices,@ January 22, 2001, http://interactive.wsj.com/arichive/retrieve.cgi?id=BT-CO-20010122-0011943.djml.

17. Electric Generation and Customer Choice Competition Act (1996), 66 Pa. C.S. ' ' 101, et seq.

18. PennFuture, a Pennsylvania public interest organization, has monitored the development of the Pennsylvania energy markets closely. See http://www.pennfuture.org

19. Pennsylvania PUC, Final Order, Guidelines Addressing Return of Customers to Provider of Las Resort Service, Docket No. M-00960890F0017, June 22, 2000.

20. Pennsylvania PUC, Joint Petition for Full Settlement of PECO Energy Company=s Restructuring Plan and Related Appeals and Application for a Qualified Rate Order and Application for Transfer of Generation Assets, Docket No. R-00973953, Order Approving Settlement, May 14, 1998, Issue L, Paragraph 38.

21. Another provision of this CDS requires that a supplier must provide at least 2% of its offered energy supply for CDS service from renewable resources in order to be a qualified bidder. This increment must increase annually by .5%. The Commission can reduce this requirement if the cost of power from the renewable resources increases the cost of the entire block by more than 2% over what the power would cost without the renewable requirement.

22. **Annex A, PECO Energy rules for Competitive Default Service, February 28, 1999, Q.7(b).**

23. Pennsylvania PUC, Application of PECO Energy Co., Pursuant to Chapters 11,19,21 and 28 of the Public Utility Code, for Approval of a Plan of Corporate Restructuring..., Order, Docket No. A-110550F0147, June 22, 2000. As part of the merger settlement, the transmission and distribution rate cap was extended until December 2006.

24. Pennsylvania PUC, PECO Energy Co. Competitive Default Service Program Bidding: Joint Approval of Competitive Default Service Coordination Agreement, Order, Docket No. A-110550F0147, November 20, 2000.

25. Pennsylvania PUC, Press Release, January 19, 2001.

26. An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, House No. 5117, November 19, 1997.

27. G.L. c. 164, ' 1B(d) and implemented in the Massachusetts DTE regulations, 220 C.M.R. ' 11.04.

28. Massachusetts DTE, Letter to Massachusetts Electric Company regarding Pricing for Default Service, June 1, 1999.

29. Order Instituting a Notice of Inquiry/Generic Proceeding into the Pricing and Procurement of Default Service, D.T.E. 99-60, June 21, 1999.

30. Ibid, Order at 2.

31. Massachusetts DTE, Investigation by the DTE on its own Motion into the Pricing and Procurement of Default Service Pursuant to G.L. c. 164, ' 1B(d), Order, DTE 99-60-B, June 30, 2000.

32. Order Addressing Recommendation of the Working Group on Default Service Issues, DTE 99-60-C, October 6, 2000.

33. Ibid., at 10.

34. Re: Standard Offer Service Fuel Adjustments, DTE 00-66, 00-67, 00-70, December 4, 2000. The consumer organizations complained that this decision had been reached without the development of record evidence as to the fuel procurement practices of the utilities, but did not object to the Department=s analysis of the legislation and the ongoing deferrals

of fuel costs. Whether or not the Legislature exempted fuel costs from the rate reductions, the public education materials by all parties never explained to the public that the rate decrease would be subject to reconciliation of fuel costs in the future. See, e.g., the DTE website explanation of Electric Restructuring in Massachusetts: http://www.state.ma.us/dpu/restruct/competition/index.htm.

35. An Act to Restructure the State=s Electric Industry, P.L. 1997, ch. 316 (codified as Chapter 32, of Title 35-A, M.R.S.A. ' '3201-3217).

36. The California statute did not require divestiture, but there were economic incentives if a utility divested its fossil fuel generators. Pennsylvania=s statute prohibited the PUC from requiring divestiture.

37. Chapter 301, Standard Offer Service, eff. July 31, 1999.

38. Order Designating Standard Offer Provider and Rejecting Certain Bids (CMP), Docket No. 99-111, December 3, 1999. The successful bidder was Energy Atlantic, an affiliate of Maine=s smallest investor-owned utility, Maine Public Service Co.

39. Kennebec Journal, March 20, 2001..

40. Bill 5005, An Act Concerning Electric Restructuring, Public Act 98-28.

41. Docket No. 99-03-36, DPUC Determination of The Connecticut Light and Power Co. Standard Offer, October 1, 1999 and December 15, 1999; Docket No. 99-03-35, DPUC Determination of United Illuminating Co. Standard Offer, October 1, 1999.

42. As of October 2000, only 175,196 residential customers had selected a competitive marketer or ESCO, 3.2% of the statewide total. By December 2000, the residential customer migration had increased slightly to 3.4% of all residential customers. By far the largest number are customers of Consolidated Edison (41%) and Niagara Mohawk Power (24%). The New York PSC publishes customer migration statistics at http://www.dps.state.ny.us/Electric_RA_Migration.htm.

43. New York Public Service Commission, Case 96-E-0897, In the Matter of Consolidated Edison Co. of New York, Inc.=s plans for Electric Rate/Restructuring pursuant to Opinion No. 96-12, February 28, 2000. See also Opinion 97-16 at 2, (ANew York City and Westchester consumers will receive lower average electric bills.@), 15 (AFor all other customers, there wil be a 10% rate reduction phased in over the term of the Settlement.@), 26 (AThe 10% cumulative base rate reduction for commercial and residential customers is firm, and no longer dependent on future contingencies.@)

44. Office of the State Comptroller, New York, AElectric Deregulation in New York State: The Need for a Comprehensive Plan,@ February, 2001, Chart C.

45. PSC data as summarized by the Public Utility Law Project in their comments on the PSC Price Spike Mitigation Proposals, see fn. 42.

46. Wall Street Journal, AMismanagement of NY Power Mkt Costs MillionsBUtilities,@ October 5, 2000, http://www.interactive.wsj.com/archive/retrieve.cgi?id+DI-CO-20000105-006703.djml

47. See, Department of Public Service Pricing Team, Interim Pricing Report on New York State=s Independent System Operation, December 2000; ACon Edison Asks FERC to Close Loopholes That Enable New York Generators to Exercise Market Power; Additional Price Protection for Customers and a More Competitive Marketplace Sought,@ Con Edison Press Release, March 2, 2001; APSC Chair Announces Five Point Plan for Regional Energy Markets and Managing Demand for Electricity,@ PSC Press Release, February 20, 2001.

48. New York PSC, Case 00-M-0504, Proceeding on Motion of the Commission regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities.

49. Energy Competition Next Steps, Draft Phase I and II Consensus Report, Case 00-M-0504, January 2001.

50. Press Release, New York State Electric and Gas Co., ANYSEG Proposes Electric Price Protection Plan that Freezes Rates and Assures Energy Reliability,@ March 8, 2001, http://www.nyseg.com .

51. See, ex., Comments of the Public Utility Law Project on Price Spike Mitigation Proposals, Case 96-E-0897, March 13, 2001, http://www.pulp.tc/html/pulp_s_comments_on_price_spike.HTM

52. ANYSEG Proposes Electric Price Protection Plan that Freezes Rates and Assures Energy Reliability,@ NYSEG Press Release, March 8, 2001.

53. AB366 (1997), amending Chapter 703 and 704 of NRS.

54. PUCN Docket No. 97-8001 (Provider of Last Resort Service), Version for hearing December 30, 1998; Notice of Hearing published November 20, 1998.

55. Attorney General, Bureau of Consumer Protection, Comments Regarding Provider of Last Resort Service, Docket No. 97-8001, October 13, 1998, at 2.

56. SB 438, Chapter 600, Statutes of Nevada, 1999.

57. Available at: http://www.state.nv.us.

58. Senate Bill 7, amending the Public Utility Regulatory Act (PURA), ' ' 39.101, et seq.

59. Project 21409, Price to Beat Rulemaking.

60. Provider of Last Resort, Project 21408, Commission Rules, ' 25.43. The RFP was issued in December 2000, with final bids due by January 5, 2001. The Commission=s schedule calls for a decision on the bids by March 2001.

61. Pursuant to the Commission=s Consumer Protection Rules adopted for electric competition, a REP (including an affiliate REP) cannot physically disconnect a customer for nonpayment, but can only terminate service. Customers who do not transfer to another REP will automatically be provided with POLR. The POLR provider can disconnect service pursuant to the same consumer protections and procedures in effect for traditional utility service.

62. Amended Substitute Senate Bill No 3, 123rd General Assembly, eff. October 5, 1999.

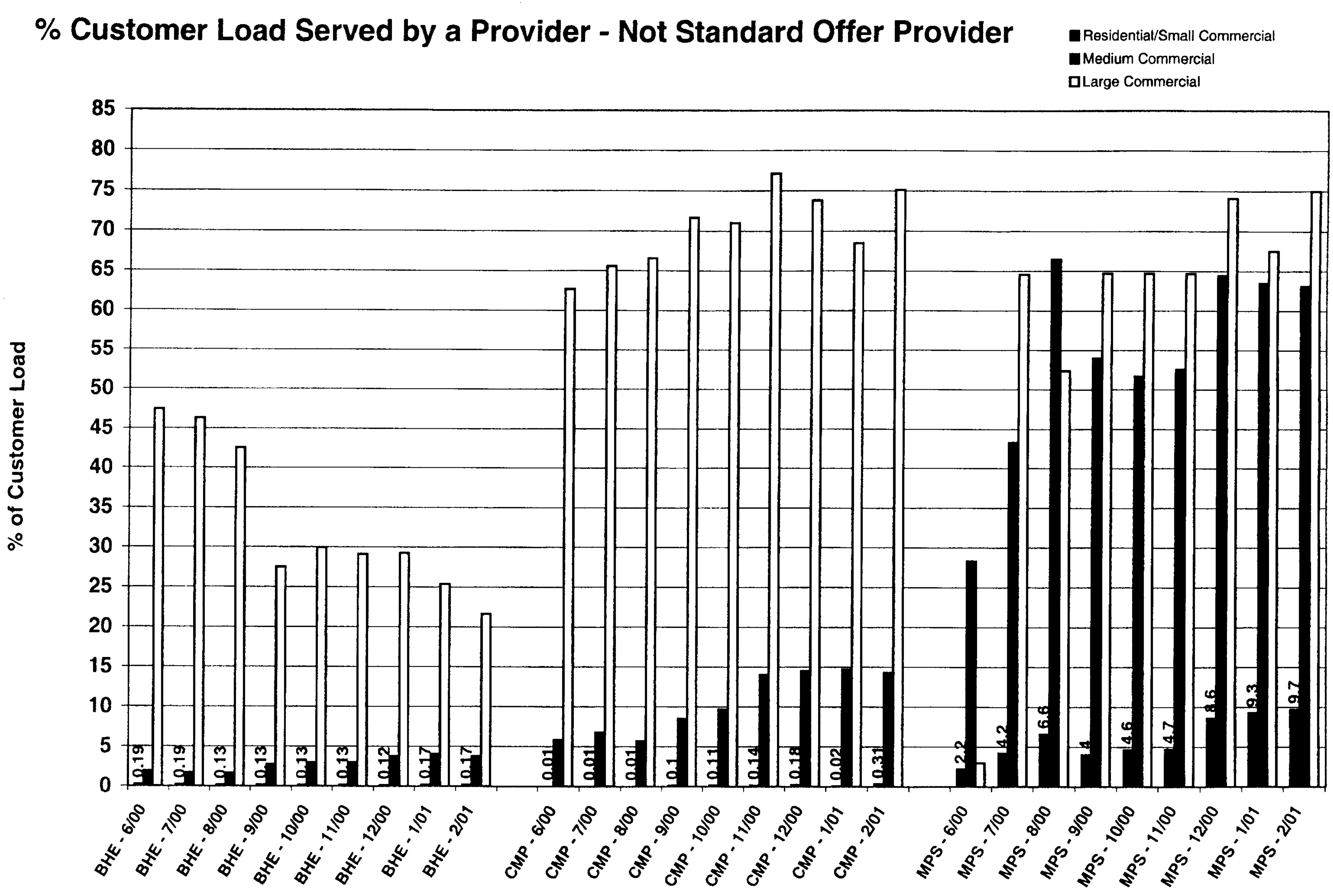
63. Sec. 4928.34 and 4928.40.

64. Rule 4901:1-10-32 and 4901:1-21-16, Ohio Administrative Code.

65. Ohio PUC, In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co. for Approval of their Transition Plans and for Authorization to Collect Transition Revenues, Case No. 99-1212-EL-ETP, Opinion and Order, July 19, 2000.

66. Sec. 4928.14.

Retail Choice: Maine, February 2001



# ELECTRICITY SHOPPING GUIDE

Maine Public Advocate Office — Volume 2 — March 2000

## PRICE UPDATE: Updated Information About Your Supply and Delivery of Electric Power

On March 1, 2000, Maine's electric industry changes. The generation of power will be deregulated and open to competition. The delivery of power will remain a regulated service of your current utility. Many people are wondering what they need to do to secure a supply of power, and at what cost.

**You do not need to do anything.** In fact, at the moment, there may be little you could do even if you wanted to. You will receive your power supply through the standard offer, a process administered by the Public Utilities Commission (PUC) pursuant to statute.

As of now, there are few if any choices for retail residential power supply other than the standard offer. This may be because the standard offer price is too low to allow other competitors the ability to undercut. It may also be due to the fact that Maine is only a small part of the New England electricity market and the remainder of New England is seeing little if any competition for residential customers. Until competition develops in other New England states, marketers may be uninterested in pitching their products in Maine.

**AGGREGATION**: When competitive choices do first appear for residential customers, they will likely come through aggregation. This is where customers form groups for the purpose of increasing negotiating leverage in order to obtain a better price, or to buy power from environmentally benign sources of supply. In future editions of the **ELECTRICITY SHOPPING GUIDE**, we will publish lists of licensed aggregators, brokers and other suppliers and indicate what type of services they offer and to what type of customers. With the consent of the supplier, we also hope to indicate prices for these services so that you can make a comparison.

**PRICES**: You will be charged for power in two ways. One charge will be for **delivery** from your current utility, and the other will be for **supply**. You will still only receive one bill and will only have to write one check. We have attempted to summarize your rates in the accompanying rate chart.

*"Electric Restructuring Begins March 1, 2000"*

**March 2000**

| Sun | Mon | Tue | Wed | Thu | Fri | Sat |
|---|---|---|---|---|---|---|
| | | | **1** | 2 | 3 | 4 |
| 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| 12 | 13 | 14 | 15 | 16 | 17 | 18 |
| 19 | 20 | 21 | 22 | 23 | 24 | 25 |
| 26 | 27 | 28 | 29 | 30 | 31 | |

## RESIDENTIAL AND COMMERCIAL ELECTRICITY PRICE CHART

| | | Delivery Charge | Supply Charge (Standard Offer) | Total Electric Rate | Overall Average Percent Decrease |
|---|---|---|---|---|---|
| A. | **Central Maine Power** | | | | |
| | 1. Residential Rate A | 7.8¢ | 4.1¢ | 11.9¢ | -9.8% |
| | 2. Small Commercial, SGS | 8.0¢ | 4.1¢ | 12.1¢ | -9.8% |
| | 3. Medium Commercial, MGS-S | 4.4¢ | 5.9¢ | 10.2¢ | -3.3% |
| | 4. Medium Commercial, MGS-P | 4.1¢ | 5.9¢ | 10.0¢ | 0% |
| | 5. Large Commercial, IGS-S | 4.6¢ | 5.2¢[1] | 9.8¢ | -4.1% |
| | 6. Large Commercial, IGS-P | 3.8¢ | 5.2¢[1] | 9.0¢ | -1.7% |
| B. | **Bangor Hydro-Electric** | | | | |
| | 1. Residential Service | 9.6¢ | 4.5¢ | 14.1¢ | -2.8% |
| | 2. Residential Water Heat | 9.3¢ | 4.5¢ | 13.8¢ | -2.9% |
| | 3. Commercial Service | 8.7¢ | 4.9¢[2] | 13.2¢ | -3.0% |
| | 4. Commercial Water Heat | 7.3¢ | 4.9¢[2] | 11.8¢ | -3.4% |
| C. | **Maine Public Service** | | | | |
| | 1. Residential Service | 7.4¢ | 4.3¢ | 11.7¢ | -8.2% |
| | 2. Commercial and Farm, C | 7.2¢ | 4.3¢ | 11.5¢ | -3.7% |
| | 3. Large Commercial, ES | 4.8¢ | 4.3¢ | 9.1¢ | -4.0% |
| | 4. Large Commercial, EP | 4.5¢ | 4.3¢ | 8.7¢ | -4.9% |

[1] 6.81¢ Summer, 5.52¢ Winter; possible upward adjustments could occur by PUC order.

[2] 5.24¢ Summer, 4.25¢ Winter; possible upward adjustments could occur by PUC order.

> NOTICE— The percentage price decreases listed in this chart relate to the kilowatt hour rate and not necessarily to your monthly bill. Whether you end up paying less for your electricity will depend in part upon these rates, but also on how much electricity you use.

## WARNING FOR SMALL CUSTOMERS

There has been much publicity about big reductions in electric bills beginning March 1, particularly from CMP's public relations people. Actually, not everyone will be receiving the same percentage decreases (summarized above) even if they all belong to the same residential rate class for the same utility.

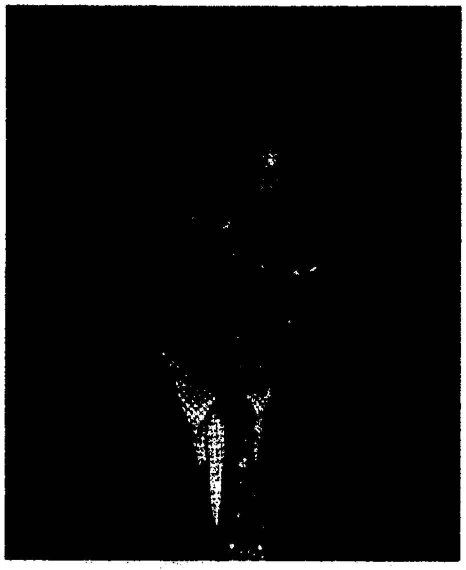
**Here's the reason:** when the Maine PUC set new rates for the distribution of electricity (removing supply costs), it also set a price for residential customers that is the same rate regardless of usage (flattening the rate). In a December 1999 order the PUC eliminated the "inclining block rate" for residential customers.

**The upshot is that** residential customers using substantial amounts of electricity (for space heat and for water heating) will receive much larger bill reductions than customers using smaller amounts of electricity. In fact, customers taking service at summer camps and seasonal homes may receive no significant reduction in their annual electricity costs, compared with previous years.

**A word to the wise:** look for ways to conserve electricity in order to reduce your electricity bill and don't pay too much attention to utility press releases.

# Shopping For Electricity: Advice from Public Advocate Stephen Ward

In March Maine joins 22 other states in breaking the power companies' monopoly over the supply of electricity and letting consumers select the suppliers they want. In time, this form of consumer choice is likely to lead in a number of positive directions in my opinion. For example, innovations in the area of electric generation such as micro-generation, fuel cells and less polluting technologies are likely to develop. We also are likely to see the rapid development of renewables and "green" power sources as individual customers and businesses choose these suppliers over traditional fossil-fuel powered generators.



***Stephen G. Ward, Public Advocate***

As probable as these developments may be, they will not be available right away. In fact, at the outset of electric competition in the Spring of 2000 there will be precious few suppliers who have been certified eligible to sell power in Maine and who target their marketing at small residential and commercial customers. In contrast, large commercial and industrial customers are likely to have their pick of a number of providers (ENRON, Maine Electric Consumers' Cooperative, Florida Power and Light Select Energy) while public agencies, school districts and water departments will be solicited by Maine Health and Higher Education Financing and by the Maine Municipal Bond Bank.

This is the good news since, if they do not shop, these larger customers will have to settle for the relatively expensive Standard Offer prices that have been arranged as a back-up for them by Maine's PUC. On a year-round, average basis, these prices are high (from 5.18¢ per kilowatt-hour to 5.86¢ per kilowatt-hour for CMP's large commercial and medium commercial customers, respectively). But they become dramatically more expensive for June, July, and August when the New England Power Pool hits its summer peak. CMP's summer-period Standard Offer pricing for commercial customers exceeds 6.8¢ per kilowatt-hour. To avoid these high summer-period prices, medium to large customers really need to line up a supplier before June 2000.

Residential customers and commercial customers whose monthly demand is less than 20 kilowatts are much more fortunate. The PUC has now put into place very attractive Standard Offer prices for all homeowners, renters and small businesses at 4.1¢/kwh for CMP customers, 4.3¢ for Maine Public customers in Aroostook County and 4.5¢ for Bangor Hydro customers in Eastern Maine. These electricity supply prices are as attractive as any supply prices available anywhere in New England and are clearly cheaper than the medium to large commercial customers referred to earlier.

The upshot is that small residential and commercial customers don't have to worry about shopping for power, at least initially. If you want to take advantage of renewable and "green" power supply options, it appears there may be some opportunity – from Interfaith Light and Power, for example, or in time from GreenMountain.com. However, the good news is that small residential customers and small businesses will be able to take advantage of relatively low prices without shopping at all – unlike the large business customers.

One final note: as a result of the restructuring of Maine's electric industry, residential and small business customers are going to start off in March 2000 with a noticeable price reduction in total electricity bills - *depending on usage* - for CMP customers price reductions could range from 2.5% to 15%, for Bangor Hydro residential customers around 2.5% and for Maine Public Service residential customers around 8%. These reductions will serve to bring the cost of Maine's electricity (supply and delivery costs together) closer to the national average. These reductions represent a permanent reduction in the cost of electric service in Maine and result from three hard-fought rate cases at the PUC that began in 1997 and finally have been resolved.

Please do not hesitate to contact me or my staff by phone, mail or E-mail with any questions you may have about electric restructuring or utility service generally. It is our pleasure to serve you.

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## CMP's TIME-OF-USE CUSTOMERS

If you are a time-of-use customer of CMP, that is if your rate varies depending upon the time-of-day, you will have the option of moving into the Rate A category (see the rate chart) or keeping a time of use rate structure. You may want to contact CMP for a full description of these options.

# ELECTRICITY SHOPPING GUIDE

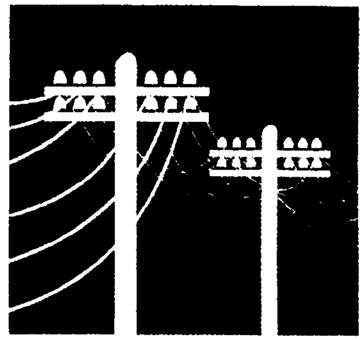
Maine Public Advocate Office ... October 2000

## THE STATE OF ELECTRIC COMPETITION

The retail sale of electricity has now been open to competition in Maine for six months and it is safe to say that competition has not swept Maine's residential consumers off their collective feet. The reasons are the same as were reported in our last issue: there is little competition in the New England wholesale market and, with the exception of Bangor Hydro, there are low standard offer prices that competitors cannot beat. Interestingly, there has been relatively significant activity in Aroostook County, where more than 4% of customers have switched to a competitive supplier. [See **Aroostook County: "The Home Team Advantage" page 3.**] In other parts of the state, however, competitive suppliers have wooed less than one percent of customers away from the standard offer.

Looking at it another way, however, we can say that between 20 and 40% of the kilowatt hours sold in the state (depending upon which utility territory you are in) are being provided by competitive suppliers. The reason for this is that many of the state's industrial customers, some of whom measure their service in megawatts, not kilowatts, have contracted with competitive suppliers. Thus, although there are few such customers, they represent a large percentage of the overall load. These findings are detailed in the chart on page 2. By contrast, in Pennsylvania, where the electric industry was restructured about a year earlier than in Maine, only two of seven utility territories have total "migration" rates (in terms of kilowatt hours) that are higher than 18%.

Customers in the service territory of Bangor Hydro are in a unique and unenviable position with regard to energy supply. Last year, when the Commission sought to determine who would provide standard offer service and at what price, the only bids received to serve Bangor Hydro customers were rejected because they were deemed to be too high. Bangor Hydro itself was then ordered to secure energy for the standard offer. With the approval of the PUC, Bangor Hydro procured 40% of the energy mix through the New England spot market. The remainder was purchased via long-term contracts. As a result, Bangor Hydro's standard offer customers have been exposed to some of the fluctuations in that market, which are in turn subject to the volatile worldwide energy markets.



Because of price increases in the New England spot market, the Commission recently approved an increase in Bangor Hydro's standard offer prices, effective October 1, 2000. After that date, the standard offer price for residential service will be 6.1 cents. The PUC chairman indicated that this amount is still below the price contained in the lowest bid received in last fall's failed auction. This new standard offer price, when combined with the distribution price, results in a total price to Bangor Hydro residential customers of 15.5 cents/kWh through February 2001. Beginning in March 2001, a new standard offer price will be put in place for Bangor Hydro customers. That price will be the result of a bid process that begins this October.

The Public Advocate agrees with the chairman of the PUC that this new high price is not attributable to deregulation in Maine. If anything, it is likely that the restructured form of regulation has only changed the timing of the imposition of this price increase upon customers. We think it likely that, as historical (stranded) costs are paid off and as the distribution rates decrease as a result, Bangor Hydro's residential total electric price will come down over the next five years. Much depends, however, on the regional wholesale market.

| NUMBER OF CUSTOMERS SERVED BY A PROVIDER OTHER THAN THE STANDARD OFFER PROVIDERS OF 8/31/00 | | | | |
|---|---|---|---|---|
| | Residential/Small Commercial | Medium Commercial | Large Commercial | Total |
| Central Maine Power | 76 | 409 | 117 | 602 |
| Bangor Hydro-Electric | 35 | 30 | 6 | 71 |
| Maine Public Service | 1,375 | 95 | 10 | 1,480 |

| % OF CUSTOMERS SERVED BY A PROVIDER OTHER THAN THE STANDARD OFFER PROVIDERS OF 8/31/00 | | | | |
|---|---|---|---|---|
| | Residential/Small Commercial | Medium Commercial | Large Commercial | Total |
| Central Maine Power | .01 | 3.7 | 25.2 | [illegible] |
| Bangor Hydro-Electric | .03 | 23 | 9.4 | [illegible] |
| Maine Public Service | 3.8 | 47.3 | 58.8 | [illegible] |

| % OF CUSTOMER LOAD SERVED BY A PROVIDER OTHER THAN THE STANDARD OFFER PROVIDERS OF 8/31/00 | | | | |
|---|---|---|---|---|
| | Residential/Small Commercial | Medium Commercial | Large Commercial | Total |
| Central Maine Power | [illegible] | [illegible] | [illegible] | [illegible] |
| Bangor Hydro-Electric | [illegible] | [illegible] | 42.5 | [illegible] |
| Maine Public Service | 6.6 | 66.5 | 52.4 | [illegible] |

## WILL THE "CALIFORNIA" PROBLEM OCCUR IN MAINE?

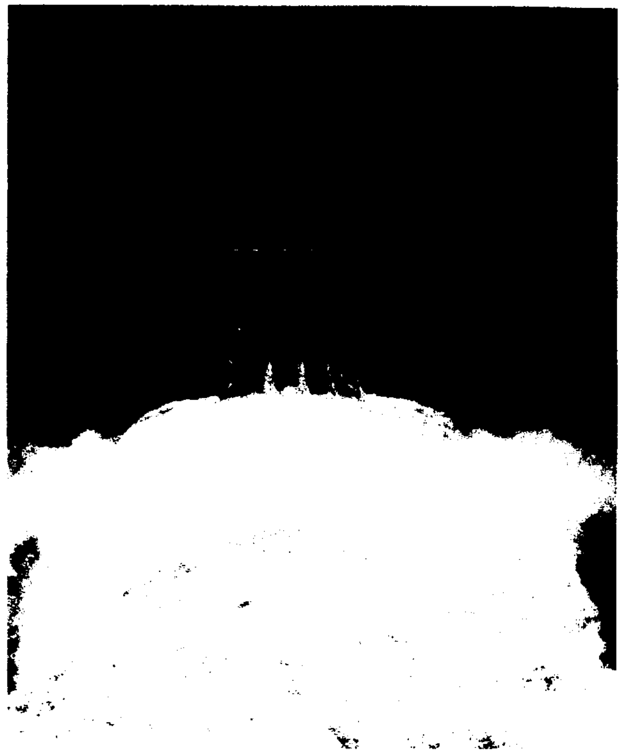
California, the first state to restructure its electric industry, has been in the news recently and the news has not been good. In the San Diego area, customers have been frustrated and angered by price spikes that in some cases have led to bills being three times their pre-restructuring levels. Will that happen here in Maine? We think not, for two primary reasons.

First, southern California has seen a significant increase in the electricity needs of customers, largely because of business and population growth, during a time when no new generation plants are being built. So, failure to build new generators and sharply increased demand have combined to contribute to higher prices. By contrast, in Maine and the rest of New England, there has been relatively little business and population growth but several new generation plants have been built and a few more are under construction. (Most of these new plants will use natural gas to generate electricity, including new plants in Maine providing 1500 megawatts of power.)

Second, the California standard offer is different than ours in at least one important way. In Maine, we have relatively fixed standard offer retail prices which shield customers from what can be large increases in the wholesale price of electricity. In California, however, the default power provider is allowed to "flow through" all of these price changes so that customers never know what their overall power bill is likely to be from one month to the other. In response to these fluctuations, the California PUC just "reregulated" electricity by establishing a price cap.

Although there could be supply price increases in Maine, we are not as vulnerable to swings in the wholesale market as they are in California.

# GREEN POWER



As of today, there is still only one "green" electricity product on the market and that is Energy Atlantic's PureGreen. After an initial splash, Energy Atlantic has done little to advertise this product, and we are unsure how many customers have signed up. Another entity, known as Maine Interfaith Power & Light, has received a license from the Public Utilities Commission and is seeking letters of intent from potential customers interested in buying power generated from renewable resources. As an aggregator, however, they must obtain a sufficient number of potential customers before they can seek to match customers with suppliers.

**What is green power?** Legally, green power has not yet been defined. It is a term, however, most often used to describe power that is generated in a manner that is the least harmful to the environment. Examples include solar, wind, hydro and biomass burners.

# DISTRIBUTION SERVICE

Although the generation of electricity has opened up for competition, delivery remains a regulated monopoly. There are two mergers to report on, however, one now completed and the other just begun.

<u>CMP</u>. Energy East recently completed its acquisition of Central Maine Power Co. having paid CMP's shareholders $900 million. Energy East, a holding company that owns New York State Electric and Gas and two Connecticut gas utilities, received Maine PUC approval for this acquisition on January 4, 2000. CMP will remain regulated by the Maine PUC. Under a 7-year price cap plan approved on September 18 by the PUC, CMP's rates will be capped through 2007 at a predetermined fraction of the annual inflation rate. We project rate decreases for CMP's distribution rates of almost $140 million over the seven-year period ending in 2008.

<u>Bangor Hydro.</u> In July, Bangor Hydro announced that it had signed an agreement to be acquired by a Nova Scotia holding company known as Emera Inc. for $206 million. Emera owns Nova Scotia Power, a utility that serves almost all the electric customers in Nova Scotia and has indicated that if the merger is approved and completed, Bangor Hydro will retain its name and its local management. There are many questions that will be asked and answered prior to a final PUC decision in February 2001. At this point, the Public Advocate's Office is investigating this matter but has not taken a position on the application. If this merger is approved and completed, Bangor Hydro will remain regulated by the Maine PUC. The PUC has already stated its desire to establish a price cap plan for BHE that is similar to the 7-year plan approved for CMP on September 18.

## AROOSTOOK COUNTY: "THE HOME TEAM ADVANTAGE"

Customers of Maine Public Service, serving the majority of Aroostook County have switched to competitive suppliers in greater numbers than elsewhere in the state. As of August 31, 1,480 customers out of a total of 36,540, representing 38.1% of the total load, had left the standard offer. There are a couple reasons for this. Energy Atlantic, the same company that won the bid to serve CMP's residential standard offer customers, is headquartered in the area. Its local presence is apparently a significant factor in encouraging customers to switch. Energy Atlantic's primary competitor in Northern Maine, WPS Energy Services, ran radio advertising during the summer and convinced some customers to switch. Then, in August, Energy Atlantic advertised a product with a price somewhat (just barely) lower than the standard offer and induced some customers, particularly medium sized commercial customers, to switch.

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## LICENSED SUPPLIERS

To date, the PUC has issued thirty-three licenses to competitive electricity suppliers. Many of these licensees are not yet active, and most that are work only with large customers. For a list of licensees contact the PUC at 287-3831 or visit **http://musashi.ogis.state.me.us/puc/html/electricsuppliers.htm**

## ABOUT THE PUBLIC ADVOCATE OFFICE

Stephen G. Ward, the Public Advocate, and his staff of seven represent Maine's telephone, electric, gas, and water customers before the Maine Public Utilities Commission, the courts, and federal agencies. Our mission is to work for reasonably priced, safe, and reliable utility services for Maine people. Website: **http://janus/state.meus/meopa** (Telephone 287-2445)

# ELECTRICITY SHOPPING GUIDE

**Maine Public Advocate Office** **Volume 4 — March 2001**

## SUPPLY PRICES INCREASE

### The Wholesale Electric Market Reflects World-wide Fuel Cost Increases

As a result of dramatic increases in the regional price of power, the cost of the supply, or generation, portion of the electric bills of most Maine consumers is going up. These changes will first appear in March bills.

Since March 1st of last year, electricity has been sold in essentially two pieces. Your local utility (CMP, Bangor Hydro, etc) delivers power on the poles and wires. The price for this portion of you bill is likely to remain stable. (See Distribution Service, p. 5) Our greatest cause for concern on behalf of Maine electricity consumers is the cost of generation. Unlike distribution service, the supply of electricity is exposed to costs and influences beyond the reach of state regulators. For example, high oil and natural gas prices are contributing to a recent increase in regional wholesale electricity prices. (For a more detailed explanation of the New England wholesale market, and how it compares to California, see page 2.) The supply price in Maine is determined largely by the standard offer price, which in turn is put in place by the PUC. The PUC has recently approved standard offer default prices that became effective on March 1, 2001. (See Chart below.)

**FORGET THE BASICS?**
**See page 5 for a REFRESHER.**

Across the state, standard offer prices vary depending on which utility delivers your power and the size of the customer. There are three standard offer classes, residential/small business, medium commercial and large

**Residential Rates for period from March 1, 2001 through February 28, 2002**
(standard offer rates in this chart also apply to small business customers)

| SERVICE TERRITORY | STANDARD OFFER | DISTRIBUTION RATE | TOTAL RATE* |
|---|---|---|---|
| CMP | **4.09¢[1]** | **7.84¢** | **11.93¢** |
| BHE | **7.3¢[1]** | **9.41¢** | **16.71¢** |
| MPS | **5.6¢** | **7.34¢** | **12.94¢** |
| EMEC | **6.23¢** | **7.20¢** | **13.43¢** |
| Houlton Water Co. | **5.58¢** | **1.95¢** | **7.52¢** |
| Kennebunk Light | **3.86¢** | **1.14¢** | **5.00¢** |
| Madison Electric | **6.84¢** | **2.98¢** | **9.82¢** |
| Van Buren Light | **5.76¢** | **2.15¢** | **7.91¢** |

*This total rate does not include any monthly customer charge that you may pay.

[1]These standard offer rates could be increased by the PUC during the next year based upon actions taken by the Federal Energy Regulatory Commission (FERC) or further disruptions in the wholesale market.

commercial. Residential/small business customers will see the lowest (average) prices relative to the other two classes. For such customers in Bangor Hydro's territory, however, this is small consolation, as they will see a significant price increase. Only residential/small business customers in CMP's territory are immune from this year's supply price increases since their 4.1¢ standard offer rate remains in effect until March 1, 2002.

Who is the supplier? This is a pertinent question since there has been a departure from the method for standard offer selection that was envisioned in Maine's Restructuring law. Originally, the standard offer supplier was to be selected by the PUC from among those independent licensed supplier/generators who bid in response to an auction. For example, CMP's residential/small business customers are served by a company called Energy Atlantic because it submitted the winning bid for serving that class of customers in March 2000.

However, the law contains an "out" in the event that the only bids received are considered by the PUC to be unacceptable. In this event, the PUC may require the distribution company to obtain electricity supply from the wholesale market. This has occurred for all medium and large customers in CMP and BHE distribution territory, and for residential/small business customers of BHE. When supply is obtained in this fashion, there are two important things to remember. First, the PUC works closely with the distribution utility to insure that the power is obtained at the best price available. Second, the utility is compensated only for its administrative expenses; the power costs are treated as a "pass through" and shareholders of the utility are kept neutral, they neither gain nor lose on the transaction. To quote a utility executive, "we are the agent of the PUC for standard offer service." Both the PUC and the utilities, having sold their generation assets two years ago, would prefer not to have the utilities in this position. The PUC will be closely monitoring this situation, including activity in the regional market, in the coming months.

What does the future hold? It is dangerous to predict future prices in a commodity market, especially in an industry with immature markets. We can say, however, that the "forward markets", that is, the current price for power to be delivered in the future, show moderate price reductions in electricity supply for 2002. However, we know that distribution service, by its nature, is stable, and we know that the stranded cost component (the cost of past PUC-approved expenditures) of your rates will only be coming down over time. It is only the supply costs, therefore, which are difficult to predict and are the cause of current worries.

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## WILL MAINE CONSUMERS OF ELECTRICITY FACE THE CALIFORNIA PROBLEM?

For many decades, Americans have been able to take entirely for granted the continual supply of electricity to their homes and businesses. Recently, however, Californians have seen this supply evaporate when it is most needed. With no earthquakes, ice storms or other physical causes, blackouts have occurred throughout the state. Furthermore, there have been sharply higher wholesale prices. Knowledgeable commenters point to a variety of reasons, but to most people the culprit is man-made "deregulation." What *are* the reasons for California's problems, and, more importantly, could those problems be repeated here in Maine?

First, we must acknowledge that large price spikes are theoretically possible in Maine and New England. After all, here as in California, prices in the wholesale market for electricity are no longer subject to direct regulatory control. However, there are enough major differences between the situation in California and Maine to give us a great deal of comfort. Here is a brief description of those major differences:

Supply and Demand. California has seen large increases in demand for power over the last ten years with almost no new power plant construction. California's load (demand for power) has increased 17% in the last 44 months. Its supply (the number of power plants and other sources of generation) has not increased at all.

Also, California has been less able than in the past to import power from neighboring states because the population in those states has increased dramatically in recent years, over 50% in Nevada, for example. Furthermore, as in other parts of the country, power plants are shut down on a rotating basis throughout the winter for routine maintenance. As a result, demand has recently outstripped supply causing the need for rolling blackouts. Remember that power must be generated at the same time it is consumed because storage of electricity, unlike other commodities, is not yet commercially feasible. It is thus impossible for an electric grid to work if there is more demand than supply.

By contrast, during a time when annual load growth in New England has been around 2%, many new power plants have either been built or are now nearing completion. Maine alone has twice as much generation as it uses, making it an electricity exporting state. In fact, more than 1500 megawatts of new gas-fired units are either operating or about to operate here in Maine, at locations in Veazie, Rumford, Jay, Bucksport and Westbrook.

<u>Deregulation</u>. California was the first state to deregulate the generation of electricity and they made mistakes that we have not repeated. The current problem is occurring in the deregulated wholesale market. In California, bulk power is bought and sold almost exclusively in a spot market. Utilities that supply power through a standard offer are prohibited from securing that power under long-term contracts, and are required to turn to this spot market. As a result, they have little ability to "hedge" against the ups and downs of that market and the effects of, for example, worldwide increases in oil and natural gas prices. This, combined with a retail price cap imposed at the start of deregulation, has led to the prospect of utilities declaring bankruptcy. By contrast, though we also have a spot market, much of New England's power is bought and sold pursuant to long-term contracts. This includes Maine's standard offer suppliers.

<u>Hydropower supply</u>. California imports about 25% of its electricity from neighboring states, some coming from the large federal dams in the Northwest. There are reports that the combination of lower-than-normal rainfall and regulations on salmon runs has kept these large hydro power stations from producing as much electricity as usual. This, combined with the increased demand for power, has limited the ability of those dams to contribute to California's power needs.

There are two factors we share with California. One is that the transmission grid in each area is old and can be stressed at times of peak use. It is exceedingly difficult to build new transmission lines because of the needed land and the opposition from landowners. As indicated above, however, Maine is a supply-exporting state, and any problems in transmission are more likely to affect our neighbors to the south than to hit consumers at home.

The second factor we share with California is the potential that generators will "game" the system, either legally or illegally, in order to increase profits. While nothing has been proven, the US Department of Justice is reportedly now investigating large price increases that occurred in New England last spring and summer to determine if any laws were broken. The same suspicions have been voiced in California. With regard to forms of legal "gaming", there are efforts underway in New England to amend the rules governing the wholesale markets in order to reduce the ability of generators to gouge customers during periods of tight supply.

The bottom line is that California's problems are unlikely to visit us here in the Northeast. There will be bumps in the road to effective retail competition for electricity, but the lights should be on when we hit them.

# COMPETITIVE ACTIVITY

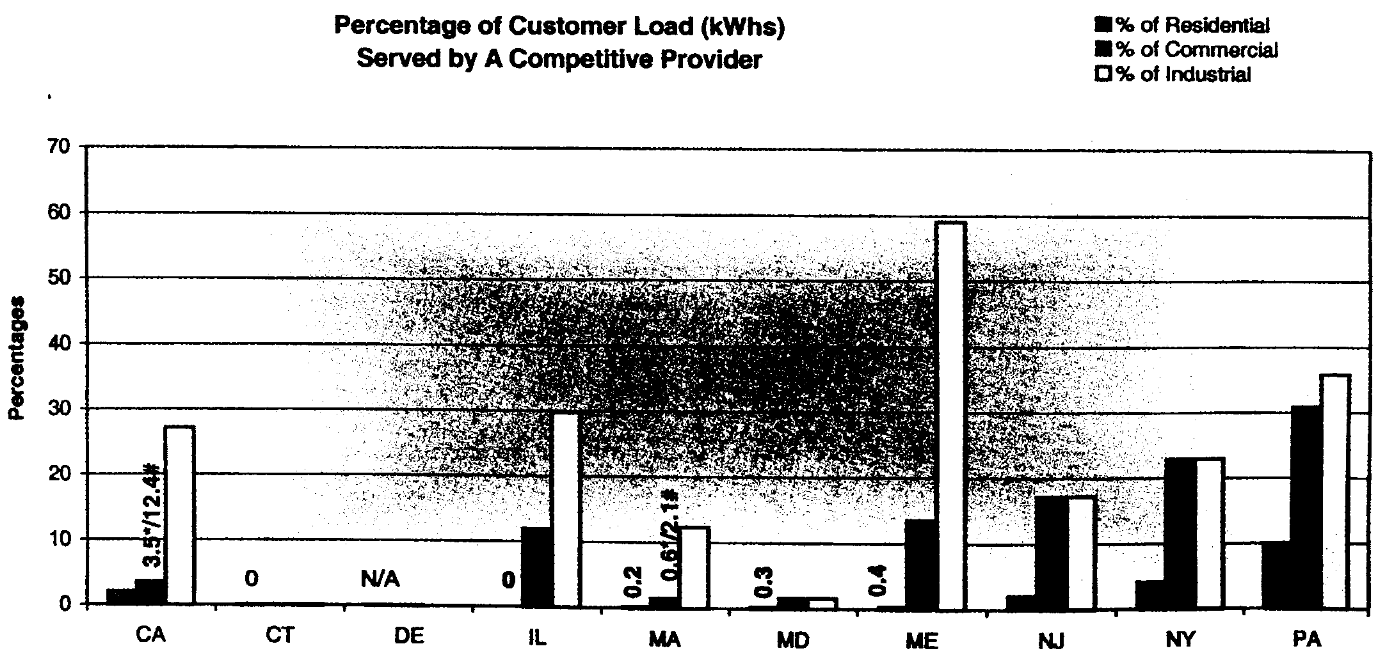
Xenergy, a Massachusetts-based energy consultant, just completed its ranking of states across the country in terms of the amount of customer load being served by competitive providers in each state. The results are shown below. Based on sources available in December 2000, Xenergy placed Maine first of the twelve states surveyed for the largest statewide percentage, at 30% of customer load, that was served by competitive providers.

**PERCENTAGE OF CUSTOMER LOAD (kWhs) SERVED BY A COMPETITIVE PROVIDER (not including "standard offer")**

| STATE | % OF RESIDENTIAL | % OF COMMERCIAL | % OF INDUSTRIAL | TOTAL % | TOTAL REVENUE ($ MILLIONS) |
|---|---|---|---|---|---|
| California | 2.0 | 3.5*/12.4# | 27.1 | 11.8 | 971 |
| Connecticut | 0.0 | 0.0 | 0.0 | 0.0 | 0 |
| Delaware | N/A | N/A | N/A | N/A | |
| Illinois | 0.0 | 11.9 | 29.7 | 14.9 | 645 |
| Massachusetts | 0.2 | 0.6*/2.1# | 12.4 | 5.8 | 96 |
| Maryland | 0.3 | 1.6 | 1.6 | 1.0 | 24 |
| Maine | 0.4 | 13.6 | 59.1 | 30.0 | 234 |
| New Jersey | 2.1 | 17.3 | 17.3 | 10.6 | 340 |
| New York | 4.2 | 22.9 | 22.9 | 17.3 | 631 |
| Pennsylvania | 10.0 | 30.9 | 35.8 | 23.8 | 1248 |

* small commercial # medium commercial

**Percentage of Customer Load (kWhs) Served by A Competitive Provider**



## DISTRIBUTION SERVICE

Distribution service remains fully regulated. The PUC has recently completed a rate plan for CMP and will soon review one for Bangor Hydro. Currently, there are no such plans for Maine Public Service or the consumer-owned distribution utilities.

CMP In our last edition, we reported that our office, along with other parties, had negotiated with CMP and Energy East (its new corporate parent) for a stipulated solution to CMP's request for a 7-year rate plan. Rates are now related to the annual inflation rate as adjusted by a predetermined productivity offset. Distribution rates are likely to decrease over the term of this plan as long as inflation remains low. The plan also contains a Service Quality Index under which CMP must maintain reliability and quality of service at or above certain thresholds or face up to $3.6 million in annual penalties. This index measures such things as the frequency and duration of outages, the average amount of time customers must wait before talking to a live customer service representative, the number of complaints filed against CMP at the PUC and customer survey responses. The purpose of this Index and the related penalties are to ensure that service quality and reliability do not decrease while the company is allowed to take steps to become more efficient.

Bangor Hydro The acquisition of Bangor Hydro by EMERA, a Nova Scotia holding company, was recently approved by the PUC. We participated in this docket and negotiated a stipulation with the merging companies and other parties. We believe, based on information gathered during this case, that ratepayers will not suffer as a result of this merger, and could actually realize some benefits by being part of a larger organization rather than a small stand-alone utility. Bangor Hydro is expected to file for approval of a rate plan this spring or summer assuming all federal approvals for the merger are received.

## RESTRUCTURING REFRESHER

Have you recently moved into Maine, or have you simply forgotten some of the basic facts about how Maine has restructured its electric industry? Here, in a nutshell, are the basics. On March 1, 2000, Maine deregulated the generation of power, and put into place a system allowing competitive electricity providers (CEPs) to sell retail electricity supply. The PUC licenses these CEPs and they are subject to an array of consumer protection laws and rules, but they are otherwise unregulated. They are not regulated as to the price of the product they sell. CEPs can be companies that own generation resources, brokers or aggregators who help customers secure supply through contract. For customers who do not wish to shop, or who cannot, supply comes through the so-called standard offer. The distribution of electricity remains fully regulated and is in the hands of utilities such as CMP, BHE and MPS who are prohibited from generating power. Since most outages occur at the distribution level as a result of storms or accidents, the reliability of service remains subject to full regulation. The legislation that made these changes requires that 30% of all generation sold in Maine must come from sources that are renewable, such as hydro, solar, or biomass, or from highly efficient sources like cogeneration facilities that use the steam or heat byproduct from manufacturing processes, such as papermaking.

### ABOUT THE PUBLIC ADVOCATE OFFICE

Stephen G. Ward, the Public Advocate, and his staff of seven represent Maine's telephone, electric, gas, and water customers before the Maine Public Utilities Commission, the courts, and federal agencies. Our mission is to work for reasonably priced, safe, and reliable utility services for Maine people.
Website: http://janus/state.me.us/meopa (Telephone 287-2445)

**Maine Public Advocate Office**
**112 State House Station**
**Augusta, ME 04333**

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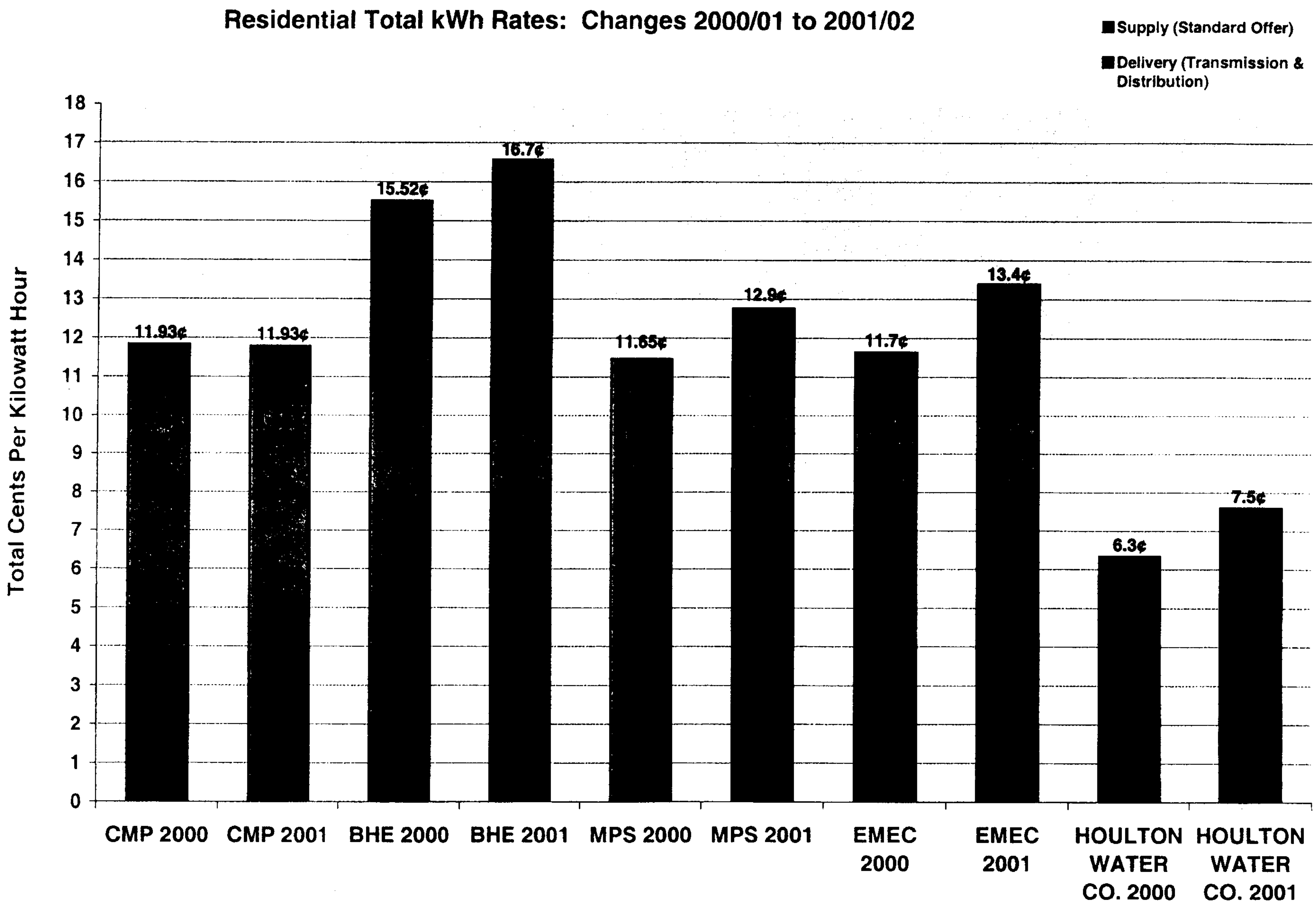
## CONSUMER RIGHTS

Your local electric (and phone) utilities continue to be regulated by the PUC. You and the utility have certain rights with regard to utility services. A utility cannot deny service based on race, gender, nationality, marital status or where you live. They may require a deposit before connecting you; if they do, they must inform you in writing. The utility has the right to charge a fee for late payments. The bill is considered paid when received by the utility. If you fail to pay, the utility may disconnect your service. Notice of disconnection is usually 14 days, but can be as little as three days in some circumstances. If you agree to a long-term payment plan, you can get special protection against winter disconnections.

A utility cannot disconnect service to a tenant at the request of a landlord or if a landlord fails to pay a bill. If you have been disconnected, the utility must reconnect service upon receipt of payment in full, although you may be charged a reconnection fee.

<u>Complaints</u> - If you have a complaint, feel free to call us (287-2445). We can help you to understand the way the utility operates, and may be able to help resolve the dispute. We may also refer you to the Customer Assistance Division (CAD) of the PUC. The CAD's job is to investigate complaints and mediate disputes between utilities and consumers. You may call them directly at 1-800-452-4699.



Residential Total kWh Rates: Changes 2000/01 to 2001/02
Supply (Standard Offer)
Delivery (Transmission & Distribution)
Total Cents Per Kilowatt Hour
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
11.93¢
11.93¢
15.52¢
16.7¢
11.65¢
12.9¢
11.7¢
13.4¢
6.3¢
7.5¢
CMP 2000
CMP 2001
BHE 2000
BHE 2001
MPS 2000
MPS 2001
EMEC 2000
EMEC 2001
HOULTON WATER CO. 2000
HOULTON WATER CO. 2001