1999

Report to the 76th Texas Legislature

The Scope of Competition in the Electric Industry in Texas

Public Utility Commission of Texas
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I. INTRODUCTION

Section 31.003 of the Public Utility Regulatory Act (PURA)[1] requires the Public Utility Commission of Texas (Commission) to provide a biannual report to the Legislature on the scope of competition in electric markets and the effect of competition and industry restructuring on customers in both competitive and noncompetitive markets. The Commission submitted its first report to the Legislature on the scope of competition in electric markets in January 1997 (1997 Scope of Competition Report).[2] Specifically, PURA §31.003 states that the report must include:

1. an assessment of the effect of competition on the rates and availability of electric services for residential and commercial customers;
2. a summary of competitive action over the preceding two years that reflects changes in the scope of competition in regulated electric markets; and
3. recommendations to the legislature for legislation that the commission finds appropriate to promote the public interest in the context of a partially competitive electric market.

Currently, the legal structure of the electric industry in Texas consists of a regulated retail market and a partially competitive wholesale electric market. That is, sales for resale are open to competition from electricity suppliers other than traditional utilities, but ultimate sales to end-use retail customers are still limited exclusively to electric utilities legally certified to provide electric service in a specific geographic area.

However, in Texas and in other states, momentum has been building in recent years to expand competition in electric markets to the retail level. Since 1995, almost every state has initiated an investigation to examine the costs and benefits of implementing retail competition. Several states have decided that competitive retail electric markets are in the public interest, and have passed legislation to open retail electric markets to competition. As of June 1998, 13 states have adopted major restructuring legislation.

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[1] Public Utility Regulatory Act, TEX. UTIL. CODE §§ 11.001 *et seq*. (PURA)

[2] *Volume I, Electric Power Industry Scope of Competition and Potentially Strandable Investment Report* and *Volume II, The Scope of Competition in the Electric Industry in Texas: A Detailed Analysis*, Public Utility Commission of Texas (Jan. 1997).

Those states include Arizona, California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia.

In addition to individual state actions, retail electric competition has received increasing attention at the federal level. As of May 31, 1998, 16 bills had been introduced in the 105th U.S. Congress related to restructuring the electric power industry.[3] Although no legislation has yet passed, the number of bills introduced is indicative of the high profile of the topic on Capitol Hill.[4] In recognition of the actions occurring around the nation, the Commission provided an extensive review of retail electric restructuring in Texas as one component of its 1997 Scope of Competition Report.

The Commission continues to support the timely move to a competitive retail market that provides adequate protections for customers and the opportunity for all market participants to benefit, as well as other provisions necessary to promote the public interest. This report will not detail this recommendation for two reasons. First, the Texas Senate Interim Committee on Electric Utility Restructuring (Interim Committee), created by Lt. Governor Bob Bullock in October 1997, is charged to study whether to create a competitive Texas electric market that is open to all retail customers and, if appropriate, to make recommendations for legislative and regulatory action. In addition, the House State Affairs Committee has been charged to assess the state and local tax impacts of possible changes in the structure of the electric power industry. Given these charges, the Commission has not duplicated the efforts of these committees in this report. In fact, the Commission has served as a resource to these committees, providing testimony at hearings and preparing topical reports at their

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[3] *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, Department of Energy/Energy Information Administration, Table 19 (July 1998). The bills include: H.R. 338, H.R. 655, H.R. 1230, H.R. 1359, H.R. 1960, H.R. 2909, H.R. 3548, H.R. 3927, H.R. 3976, S. 237, S. 621, S. 687, S. 722, H.R. 1276, S. 1401, and S. 1483.

[4] Annual electric utility industry revenues are approximately $220 billion nationwide, and approximately $17.7 billion in Texas.

request.[5] Second, the Commission addressed many issues related to retail competition in its 1997 Scope of Competition Report. Those discussions remain relevant to any retail restructuring debate, and the Commission's prior reports are available for the Legislature to review.

For these reasons, this report is focused primarily on the specific items required in PURA §31.003. That is, a summary of Commission actions over the preceding two years that reflects changes in the scope of competition in electric markets and the effect of competition on the rates and availability of electric services for residential and small commercial customers. In addition to the items required by statute, an updated summary of noteworthy competitive activities occurring in other states and at the federal level is included to provide a nationwide perspective of actions that may affect the Texas electric market.

II. COMMISSION ACTIVITIES REFLECTING CHANGES IN THE SCOPE OF COMPETITION

Over the past two years, the level of Commission activity relating to competitive issues and the change in the scope of competition in electric markets has increased dramatically. This section of the report provides an overview of those activities as required by PURA § 31.003(b)(2), and the related effects, where relevant, on the rates and availability of electric services for residential and small commercial customer, as required by PURA § 31.003(b)(1).

A. INTEGRATED RESOURCE PLANNING

State law in Texas requires each generating electric utility to go through a detailed planning process as the utility considers the best way to meet customer resource needs

[5] The Commission has prepared the following reports at the request of the Texas Senate Interim Committee on Electric Utility Restructuring: *Potentially Strandable Investment (ECOM) Report: 1998 Update* (Apr. 1998); *Revenues Supporting Low-Income, Energy Efficiency and Environmental Programs* (July 1998); and *Adequacy of the Transmission System and the Existence of Must-run Resources in a Retail Access Environment* (July 1998), Public Utility Commission of Texas.

in the future. PURA §34.003 and the Commission's rules refer to this process as integrated resource planning, commonly known as IRP.[6]

As set forth in the 1995 amendments to PURA, IRP requires each generating utility to develop a forecast of future need, and to consider a range of possible planning alternatives. The utility must develop a "portfolio" or mix of resources that will provide efficient electric service in the future at a reasonable price. Planning in a transitional environment is difficult for two reasons: (1) no one knows what the future will bring, and (2) not everyone believes that the same things are important.

One part of the IRP process requires the utility to gather information from its customers regarding their expectations about the cost and quality of electric service, environmental matters, and about the effects of utility operations on the local area and economy. The public participation portion of IRP takes place at the beginning of the process so that the results can be incorporated throughout the planning cycle. The utility is responsible for preparing a plan that incorporates its customers' values and preferences.

Among the issues that have been found to be important to customers in past IRPs are: short-term versus long-term cost; stability and predictability of electric bills; measuring cost as lowest rate or as lowest total electric bill; environmental impact; reliability; renewable energy; power plant emissions; future fuel price risk and fuel supply risk; impact on the economy; customer needs; equity among customer groups; competitive market challenges; and impact on future generations.

Although not required in the Commission's rules, many utilities have chosen to use a Deliberative Poll™ as a means of achieving customer participation in the resource planning process. Using the Deliberative Polling™ process, each investor-owned utility in Texas has sampled customer opinion on a variety of resource planning issues, bringing together about 250 randomly-selected customers. These participants learn more about IRP, and at the end of a two-day session, the customers' values and

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[6] For a more detailed account of the integrated resource planning process in Texas, please refer to the PUCT's *Statewide Integrated Resource Plan*, submitted to the 76th Legislature in January 1999.

preferences are re-assessed, using the same questions that were asked during a preliminary opinion poll. Changes in customer preferences are analyzed based on what a more-informed electorate would say about an issue, given more time to learn about the electric industry and resource planning. A key feature of the process is the small group discussions in which customers share their opinions and test their assumptions with their peers.

Another important aspect of the IRP rules is the competitive bidding requirement. Also referred to as resource solicitation, competitive bidding requires an electric utility that identifies a capacity need to allow all resource providers to bid to meet that need. The competitive bidding process in Texas uses an all-source bidding approach, which means that both demand-side and supply-side resources are considered potential candidates to meet the energy and capacity needs of the utility. The statute also sets forth restrictions on bidding by affiliates of utilities to ensure that the resource solicitation is fair. A utility affiliate must maintain an “arm’s length” relationship in its dealings with the utility, and the utility bears the ultimate responsibility for its actions. A grievance process is established during the review and approval of the selected resources to allow bidders the opportunity to voice any problems that might have arisen in the bid selection process.

Utilities in Texas have selectively used IRP as a means to address customers’ preferences for renewable resources and conservation. So far, utilities have not used IRP as a vehicle to acquire long-term resources. This may be in part a result of provisions in the rules that provide utilities with the flexibility to acquire resources on a short-term basis (two years or less) without a resource solicitation. Another important factor that limits the commitment to long-term resources is the uncertainty of the future structure of the electricity industry and market. Because many stakeholders see a restructured electric market on the horizon, a commitment to long-term resources is viewed as risky to both utilities and customers. In a time of rapid market change and uncertainty, long-term commitments may provide less flexibility and result in additional stranded cost burdens.

B. COMPETITIVE ISSUES IN RATE CASES AND TRANSITION PLANS

In the electric utility rate cases that the Commission has decided since the close of the 1997 legislative session, the Commission has dealt with emerging competition in the wholesale market for electricity and the prospect that competition may become a reality in the retail market. During the late 1980's and early 1990's, the large electric utilities in Texas began operating new, expensive generating plants, and the Commission authorized these utilities to raise their rates to recover the costs of these new plants. Since that time, a number of factors have created the opportunity for reducing rates. These factors include new, more efficient generating technologies, the emergence of wholesale competition (with new generation provided by independent power producers rather than rate-based utility generation), strong load growth, and the aging and depreciation of existing high-cost utility generating facilities.

The Commission has dealt with the rates of a number of large, investor-owned utilities, either through settlements or contested rate cases. These cases have resulted in rate reductions for retail customers and the adoption of measures that permit utilities to begin to reduce the plant costs that might be unrecoverable in a more competitive environment.

1. The Central Power & Light Company Rate Case

The first of these cases was the rate case of Central Power & Light Company (CPL),[7] which the Commission decided in October 1997. This case was the first filed after the 1995 legislative changes to the Public Utility Regulatory Act, and was a request by the utility for an 8 percent base rate increase. This case, which addressed changes in the wholesale market and the prospect of additional competition at the retail level, resulted in a reduction in CPL's rates. The impact of the case for retail customers is a $100 million cumulative reduction in CPL's rates over a three-year period. The Commission concluded that the factors that affect the level of rates for CPL would continue in the direction of lower rates. For this reason, it adopted a series of rate

[7] *Application of Central Power & Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997).

reductions, or a "glide path" which sets rates in three steps, with the rates for each step lower than the previous step.

In the CPL decision, the Commission recognized that utility generation has entered an era of declining costs. Generally, the delay in setting new rates that arises because of the need to prepare evidence and conduct a hearing on the appropriate level of rates can create an advantage either for a utility or its customers. If costs are rising or the utility is making large investments to serve its customers, the delay, or "regulatory lag," is to the disadvantage of the utility. This occurs because the utility typically is not allowed to recover its increased costs until after it justifies those costs through a full rate case proceeding. Regulatory lag, however, benefits customers in a period of increasing costs. In contrast, in a period of declining costs, the lag is to the disadvantage of the customers, because rate reductions are delayed to the financial benefit of the utility.

When utilities were constructing expensive generating plants, regulatory lag worked to the disadvantage of utility shareholders. During that period, however, the Commission adopted special measures, such as deferred accounting, to mitigate the impact of regulatory lag, to the benefit of utility shareholders. In the current period of declining capital costs, regulatory lag works to the disadvantage of customers by delaying rate reductions. The Commission concluded in the CPL case that it should mitigate the impact of this regulatory lag to benefit customers. The special measure adopted by the Commission was a rate-reduction "glide path" which sets rates in three steps, with the rates for each step lower than the previous step. The first-step rates took effect in November 1997 (and retroactively for the period that bonded rates were in effect), the second in May 1998, and the third will take effect in May 1999.

The primary competitive issue raised by CPL concerned its plant investment that might be stranded (unrecoverable) in a more competitive market. The Commission concluded that utility investment that exceeds market value (ECOM) is increasingly at risk of under-recovery as the electric industry becomes more competitive. It also concluded that current ECOM represents an obstacle to the transition to increased competition and an impediment to some utilities' ability to compete. PURA recognizes that the opening of the wholesale electric market is in the public interest and that the Commission should implement new rules, policies and principles to protect the public interest in a more competitive marketplace. In response to these concerns, the Commission directed CPL to accelerate the recovery of a portion of its ECOM ($800 million of CPL's invested capital), but reduced the rate of return on the same amount of ECOM.

The Commission concluded that this action was consistent with PURA and was an appropriate way to permit utilities to begin preparing for additional competition. The principles and conclusions underlying the Commission's decision include:

- ECOM-related investments are economically less useful in rendering service;
- balancing the equities between customers and shareholders supports the reduction of the rate of return, in exchange for accelerated recovery of investment; and
- the overall result is equitable for customers and shareholders.

The Commission is affording CPL a reasonable opportunity to recover its invested capital and a reasonable return on that capital. For the non-ECOM portion of invested capital, the rates include amounts for both depreciation and return on investment, calculated in accordance with traditional regulatory principles. For the ECOM portion of invested capital, the rates include amounts for both depreciation and return on investment; the depreciation is more rapid than is the case under traditional regulatory principles, while the rate of return is lower, but still reasonable.

2. The Entergy/Gulf States Transition/Rate Case

In October 1998, the Commission issued its final order on rehearing addressing a comprehensive transition-to-competition/rate case filed by Entergy Gulf States, Inc. (EGS).[8] This rate case was required to be filed in the 1994 Commission order approving the merger between Gulf States Utilities Company and Entergy. Unlike the

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[8] *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing (Oct. 14, 1998).

Houston Lighting and Power (HL&P), Texas Utilities Electric (TU Electric), and Texas-New Mexico Power Company (TNMP) transition plans discussed below, EGS' filing was not ultimately resolved in the context of proposed settlement agreements. Instead, EGS' proposals were vigorously contested and subject to months of contentious hearings in four phases before the State Office of Administrative Hearings (SOAH).

The Commission's order in the EGS case addresses a myriad of rate and transition issues, including the recovery of potentially stranded costs. In summary, the Commission order results in a net base rate decrease of approximately $69 million per year for the period June 1, 1996 through May 31, 1999. The actual base rate reduction is approximately $111 million per year, but this amount is offset by base rate surcharges relating to (1) an under-recovered fuel expense; (2) an under-recovered federal income tax amount; and (3) recovery of a $120 million regulatory asset in the form of an accounting order deferral (AOD).

The Commission's treatment of the $120 million AOD is the primary method in this case for dealing with EGS' transition issues. The AOD represents the unrecovered costs of EGS' operation of its nuclear facility—the River Bend Nuclear Generating Station—during the mid-1980s, when the facility became operational but before the facility entered EGS' rate base. The AOD is a small portion of EGS' current $2.6 billion in total invested capital. If the Commission left the AOD in EGS' rate base, the AOD would eventually be recovered over the remaining 12-year amortization period. By removing the AOD from rate base and allowing its recovery through a base rate surcharge over the three-year term of this docket, the Commission has accelerated recovery of that potentially strandable item, similar to the accelerated recovery treatments authorized in the CPL rate case and in the HL&P, TU Electric, and TNMP transition cases. In addition, requiring EGS to accelerate recovery of the AOD more closely ties recovery of that expense to the customers who most benefited from that expense. Even with the accelerated recovery of the AOD, EGS' customers receive significant refunds and a reduction in base rates. In short, as in CPL and the other transition cases, the Commission has reduced (but not eliminated) EGS' potentially strandable investment that could be created upon the advent of retail access. This reduction is achieved in the context of an overall base rate reduction so that customers benefit from lower rates, while the utility benefits from elimination of a potentially stranded investment expense.

3. Transition Plans: Houston Lighting & Power, TU Electric and Texas-New Mexico Power Company

In June 1998, the Commission approved transition plans for HL&P and TU Electric. While the details of each plan differ in several respects, the general concept is the same. In its orders approving the plans, the Commission stated:[9]

> In issuing this Order, the Commission emphasizes that this docket charts new regulatory waters; it is different from the traditional general rate case. Here, the Commission must strike an appropriate balance between facilitating an electric utility's transition to a competitive retail market and ensuring that the utility's ratepayers benefit during the transition period. The Commission believes that it has achieved this balance in approving accounting procedures that permit the accelerated recovery of production plant, while also approving just and reasonable base rate [credits and reductions]. If the Commission had employed the traditional general rate case paradigm in this proceeding, then achieving equilibrium would have been extremely difficult and it would have been impossible to achieve such a result in a timely manner, if it could have been achieved at all.

Subsequently, in September 1998, the Commission also approved a transition plan for Texas-New Mexico Power Company (TNMP).[10] While there are differences between the plans approved in the HL&P and TU Electric cases and the plan approved for TNMP, there are also significant similarities in terms of immediate rate reductions targeted at residential and commercial customers, mechanisms to permit the utilities to reduce their potentially stranded costs, and earnings caps.

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[9] *Joint Application to Reduce Texas Utilities Electric Company Base Rates and Approval of Certain Accounting Procedures*, Docket No. 18490, Order on Rehearing at 1 (June 25, 1998); *Application of Houston Lighting and Power Company for a Change in Accounting Procedures and Approval of Certain Base Rate Credits*, Docket No. 18465, Order on Rehearing at 1 (June 25, 1998).

[10] *Application of Texas-New Mexico Power Company for Approval of a Transition Plan and Statement of Intent to Decrease Rates*, Docket No. 17751, Order on Rehearing (Nov. 4, 1998).

a) The HL&P Transition Plan

The HL&P transition plan provides for base rate credits for certain customers in 1998 and 1999. For residential customers, the credits result in a reduction in base rate electric costs by 4 percent effective January 1998 and by an additional 2 percent in January 1999. For small commercial customers, base rate electric costs are reduced by 2 percent in 1998 and 1999. These credits are expected to result in a $166 million reduction in HL&P's revenues for the two-year period.

The plan also allows HL&P to accelerate the recovery of potentially strandable costs in 1998 and 1999 through two mechanisms: (1) the transfer of depreciation from distribution and transmission facilities to production facilities; and (2) the recording of earnings above 9.844 percent as additional depreciation on production facilities (*i.e.*, an "earnings cap"). Depreciation is the means by which a business recovers the cost of long-lived assets proportionally over their useful lives. HL&P owns assets, primarily the South Texas Nuclear Project and related assets, that are carried on the utility's accounts at a value that is higher than their expected value in a competitive market. In a competitive market, HL&P may not be able to fully recover the cost of these production assets. Under the plan, HL&P will accelerate the recovery of the potentially stranded costs by increasing the depreciation on its production assets, while reducing by the same amount the depreciation on its transmission and distribution assets. This measure, which is referred to as redirection of depreciation, permits the utility to reduce the value of its high-cost production and production-related assets, without increasing its total annual depreciation. Implementation of this measure permits HL&P to recover an additional $181 million of production-related investment in each of the two years of the plan.

The plan also provides that earnings above an earnings cap are treated as additional depreciation for HL&P's production assets. Under this mechanism, HL&P's earnings for 1998 and 1999 are subject to a 9.844 percent overall rate of return cap that is determined by a revenue requirements formula. If HL&P's actual earnings exceed the cap calculated under the formula, the earnings in excess of the cap will be booked as additional depreciation on production assets. In the proceeding, HL&P estimated that, under the earnings cap mechanism, it would be able to recover an additional $34 million of production-related investment in 1998 and $85 million in 1999.

HL&P also agreed to support legislation in the next session of the Texas Legislature to introduce retail competition in the electric industry in Texas no later than December 31, 2001, provided that the legislation affords HL&P protection and opportunities equivalent to those in the electric restructuring bill that was considered by the 1997 Legislature. A true-up provision is included in the plan in the event retail competition legislation is passed and HL&P over-recovers its stranded costs, although such over-recovery is not anticipated under the plan. Finally, in the event retail competition legislation is not enacted in the next legislative session, the plan includes an option to reverse the additional depreciation and redirection of depreciation if necessary.

b) The TU Electric Transition Plan

The TU Electric transition plan provides for base rate reductions for customers in 1998 and 1999. For residential customers, base rates are reduced by 4 percent in January 1998 and by an additional 1.4 percent in January 1999. For small commercial customers, base rates are reduced by 2 percent in January 1998. Base rates for all other customers are reduced by 1 percent in January 1998. These base rate reductions are expected to result in a $263 million reduction in TU Electric's revenues for the two-year period.

Similar to the HL&P plan, the TU Electric plan also allows the utility to accelerate the recovery of potentially stranded costs in 1998 and 1999 through two mechanisms: (1) the transfer of depreciation from distribution and transmission facilities to production facilities; and (2) the recording of earnings above TU Electric's authorized rate of return as additional depreciation on production facilities. TU Electric owns assets, primarily the Comanche Peak Steam Electric Station and related assets, that are carried on the utility's accounts at a value that is higher than their expected value in a competitive industry. In a competitive market, TU Electric may not be able to fully recover the cost of these production assets. To mitigate this potential cost recovery problem, TU Electric will accelerate the recovery of the potentially stranded costs by increasing the depreciation on its production assets, while reducing by the same amount the depreciation on its transmission and distribution assets. Implementation of this measure permits TU Electric to recover an additional $165 million of production-related investment in 1998 and $170 million in 1999.

Under the TU Electric earnings cap mechanism, the utility's earnings for 1998 and 1999 are subject to a 11.35 percent return on equity cap based upon its actual invested capital and expenses.[11] If TU Electric's actual earnings exceed the cap, the earnings in excess of the cap will be booked as additional depreciation on production assets. In the proceeding, TU Electric estimated that the earnings cap would not result in the recovery of additional production-related investment during 1998 and 1999.

TU Electric also agreed to support legislation in the next session of the Texas Legislature to introduce retail competition in the electric industry in Texas no later than December 31, 2001, with the same caveats as in the HL&P plan. Finally, as in the HL&P plan, the TU Electric plan includes a true-up provision and an option to reverse the additional depreciation and redirection of depreciation, if necessary.

c) The TNMP Transition Plan

Texas-New Mexico Power Company (TNMP) sought to reduce its base rates and accelerate the recovery of its ECOM-related assets. TNMP also proposed an earnings cap, with any earnings above the cap shared between customers and shareholders. The TNMP proposal was especially notable because the Company volunteered to introduce retail competition in its service areas beginning in 2003. The Commission adopted an order approving the major elements of TNMP's application, consistent with a stipulation filed by a number of the parties to the case.

In its order adopting the transition plan, the Commission approved base rate reductions for TNMP's customers. For residential customers, base rates were reduced by 3 percent in January 1998 and by an additional 3 percent in January 2000 and 2001. For commercial customers, base rates were reduced by 1 percent in January 1998, 2000 and 2001. The order will result in $64 million in rate reductions for the period 1998-2002. With the rate reductions and the refunds that are expected under the earnings cap, the expected benefit to customers is over $80 million for the five-year period.

The Commission also permitted TNMP to accelerate the recovery of ECOM in 1998-2002 by (1) accelerating the depreciation of production facilities and (2) recording earnings above TNMP's authorized rate of return as additional depreciation on production facilities. TNMP owns a generating plant, TNP One, that is recorded on its books at a value that is higher than its expected value in a competitive industry. The additional depreciation associated with these measures permits the utility to reduce the book value of its high-cost production assets by an additional $60 to $75 million during the 1999-2002 period.

A key element of the TNMP plan is an earnings cap. Any earnings by the utility above the earnings cap will be shared: 50 percent of the excess earnings would be refunded to customers and 50 percent would be treated as additional depreciation on production assets. Under this proposal, TNMP's earnings for 1998-2002 will be subject to a cap, based on its actual invested capital and expenses. TNMP projects that the earnings cap will result in $19 million in rate refunds and the recovery of $13 million in additional production-related assets during 1998-2002.

The primary benefits of the TNMP plan are the reduction in electricity costs for the retail customers of TNMP and the reduction of its ECOM. The Commission concluded that the plan will facilitate the orderly transition to competition, either through the enactment of legislation to introduce retail competition in Texas, or through TNMP's voluntary commitment to introduce retail competition in its service area in 2003. At the same time, the Commission's order permits it to make appropriate adjustments to the plan to respond to any action by the Legislature in the 1999 session.

[11] A utility's overall rate of return includes the cost of debt, preferred stock and common equity. The overall rate of return is less than the return on equity component; thus, a direct comparison cannot be made between HL&P's rate of return cap and TU Electric's return on equity cap.

TNMP is also implementing a retail pilot project, beginning March 31, 1999 and ending December 31, 2001, which is designed to serve as a test of the company's strategy for implementing retail competition under existing law. The retail pilot project will be implemented as a municipal aggregation pilot, providing the residents of the City of Gatesville the opportunity to access competitively-priced power. Participation in the program is voluntary, therefore customers will be allowed to elect not to participate in the program. The City of Gatesville will aggregate the participants' loads and contract for the power supply. Energy suppliers will be required to bid to provide power through requests for proposals developed by the City and TNMP. TNMP will continue to provide distribution service in the pilot area. Rates for power supply, transmission, distribution, billing and metering will be unbundled, thereby allowing participants to monitor the cost of each component of their electric service.

d) Key Benefits of the HL&P, TU Electric and TNMP Transition Plans

The prospect of a competitive retail electric market and the possibility of stranded costs related to HL&P's, TU Electric's and TNMP's high-cost production-related assets justify the accounting procedures contained in the plans. In addition, just as certain costs were deferred in the past to avoid "rate shock" for utility customers when nuclear plants were added to the utilities' rate structures, the Commission believes that it is in the public interest to balance recovery of potentially stranded costs with rate reductions for customers in this period of declining utility costs. Further, even without the prospect of restructuring at the retail level, prices in the competitive wholesale market are much lower than the regulated rates of many Texas utilities, and the Commission believes that it is in the public interest to undertake actions to attempt to reduce the disparity between wholesale and retail generation prices.

Other benefits include the efficiencies achieved by avoiding long, drawn-out rate cases. By avoiding the traditional general rate case, the Commission has effected rate reductions for the customers of HL&P, TU Electric, and TNMP in a timely manner. Moreover, the implementation of the rate cap mechanism provides benefits to ratepayers, especially in this period of declining utility costs and strong load growth.

In a traditional general rate case, rates are set based on historic sales (kilowatt-hours) and revenue (dollars) levels. Thus, if costs decline and sales grow subsequent to the rate case, the utility's shareholders retain excess earnings until such time as another rate case can be initiated (the "regulatory lag" issue, as previously described in the CPL rate case discussion). With declining costs and the strong load growth in the State, it is likely that the Commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings by minimizing the detrimental effect of regulatory lag on utility customers. However, through the application of the earnings cap mechanism, factors such as declining costs and load growth are captured automatically, and excess earnings do not accrue directly to utility shareholders. In the case of HL&P, TU Electric, and TNMP, the revenues that would otherwise constitute additional shareholder profits will instead be redirected to the reduction of potentially strandable costs.

The extreme weather conditions experienced during the summer of 1998 provide an excellent example of the benefit of the earnings cap mechanism to the customers of HL&P and TU Electric.[12] With the extraordinary heat of 1998 also came extraordinary electric bills. Had HL&P and TU Electric been subject to traditional ratemaking, the unexpected extra revenues generated during the summer would have flowed directly into the pockets of shareholders because of regulatory lag—i.e., no additional rate reductions for customers and no reduction in potentially strandable costs. However, under the rate cap mechanism, these "surplus" revenues are booked in the form of excess earnings, and are applied directly as additional depreciation to reduce the outstanding book value of the utilities' generation assets, rather than as shareholder profits. The actual dollar impact of the hot summer is projected to be significant.[13] HL&P, which projected additional depreciation as a result of the return cap of $34 million in 1998 at the time its transition plan was filed, now projects $185 million in additional depreciation in 1998 in light of the unexpected increased summer

[12] Return cap data for 1998 have not been collected for TNMP.

[13] While the enhanced revenues are due in large part to the extreme weather conditions, a portion of the revenue increase may be attributable to higher than expected weather-adjusted load growth.

revenues.[14] Likewise, TU Electric, which projected zero additional depreciation in 1998 at the time its transition plan was filed, now projects $180 million in additional depreciation in 1998 under the return cap mechanism.[15]

C. Utility Mergers and Acquisitions

One consequence of the increasingly competitive wholesale electricity market is that competing firms will seek ways to improve their position in that market. Merging with another firm is a common way to respond to competitive pressures. Electric utilities may merge with other electric utilities for several reasons. The firms may take advantage of economies of scale, the diversity in their production resources, or the diversity of their customers' demand. Electric utilities may merge with firms other than electric utilities to diversify earnings, take advantage of economies of scale and scope, reach new customers, and reduce overhead.

During the past two years, four mergers have been announced involving electric utilities subject to the ratemaking jurisdiction of the Commission. These mergers include: (1) Southwestern Public Service Company (SPS) merger with Public Service Company of Colorado (PSCo) to form New Century Energies, Inc., a new holding company; (2) the acquisition by Houston Industries, Inc., the parent company of Houston Lighting and Power Company (HL&P), of NorAm; (3) Texas Utilities Company, the parent company of Texas Utilities Electric Company (TU Electric), acquisition of Enserch; and (4) the pending acquisition of Central and South West Corporation (CSW), the parent company of Central Power and Light Company, Southwestern Electric Power Company, West Texas Utilities Company and Public Service Company of Oklahoma, by American Electric Power (AEP). Of these four mergers, the Commission's jurisdiction for review extended only to the SPS/PSCo and CSW/AEP mergers.

[14] HL&P's projection is based upon estimated annual revenues through December 31, 1998.

[15] TU Electric's projection for 1998 is based upon actual revenues through September 30, 1998.

In accordance with PURA § 14.101(b), the Commission is required to consider a number of factors in making a public interest determination addressing a merger application. These statutory issues include:

- the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, transferred, or consolidated;
- whether the transaction will adversely affect the health or safety of customers or employees;
- whether the transaction will result in the transfer of jobs of citizens of this state to workers domiciled outside this state;
- whether the transaction will result in the decline of service;
- whether the public utility will receive consideration equal to the reasonable value of the assets when it sells, leases, or transfers assets; and
- whether the transaction is consistent with the public interest.

However, in the face of the changing electric utility industry, the Commission has refined its standards for reviewing and approving mergers and has adopted a more comprehensive public interest standard than it had articulated in past dockets.

In addition to the requirements in PURA § 14.101(b), the Commission evaluates six additional criteria in making its public interest determination. These criteria, which were developed and first used by the Commission in the SPS/PSCo merger, are as follows:

- whether the merger does more than promise cost savings for Texas customers;
- whether the merger results in improvements in service to Texas customers;
- whether the merger causes Texas ratepayers to bear merger costs unrelated to corresponding benefits to Texas customers;
- whether the merger is a means of evading regulation or facilitates regulatory oversight;
- whether the merger results in concentration of market power; and
- whether the merger impedes competition.

The reasons for evaluating these additional criteria are threefold. First, the Commission anticipates that increased competitive pressures would result in cost savings and improvements in service without mergers. Therefore, a merger must, at a minimum, anticipate and guarantee specific levels of cost savings and service improvements. Second, despite uncertainty regarding the future structure of the industry and manner of regulation, the Commission recognizes the necessity of regulatory oversight in a transition period to protect the public interest. Accordingly, the Commission now requires affirmative regulatory guarantees to ensure that a merger will not allow a utility to evade regulation that it would otherwise be subject to. Finally, changes in PURA and federal law resulting in increased competition in wholesale markets necessitates a stronger focus on the competitive implications of proposed mergers.

1. Southwestern Public Service Company Merger with Public Service Company of Colorado

On August 22, 1995, SPS and PSCo, two electric utilities, entered into an agreement and reorganization plan to engage in a business combination in a merger of equals.[16] The merger agreement called for SPS and PSCo to form New Century Energies, Inc., a publicly-traded holding company registered under the Public Utility Holding Company Act of 1935.[17]

Conditions that the Commission placed on approval of the merger were: (1) the guaranteed credit of $3 million to Texas ratepayers annually during the first five years following the closing of the merger; (2) the adoption of tracking methodologies to ensure that additional short-term and long-term merger-related savings accrue to those ratepayers; (3) a prohibition against including potential increases in SPS's cost of capital due to the merger, regardless of whether such increased capital costs are offset by merger-related savings, either in the calculation of merger-related savings during the first five years, or in any rate case initiated during that period of time; and (4) a

[16] *Application of Southwestern Public Service Company for Sale, Transfer or Merger with Public Service Company of Colorado*, Docket No. 14980, Final Order (Feb. 18, 1997).

[17] Public Utility Holding Company Act of 1935, 15 U.S.C.A. §§ 79-79z-6 (West 1997) (PUHCA).

requirement that SPS must seek the approval of rates, in a rate proceeding initiated in the sixth year following the closing of the merger, which incorporate a base rate reduction of at least $3 million, so that Texas ratepayers continue to realize this minimum amount of merger savings after the first five years following the merger's consummation. The Commission determined that these conditions were necessary to secure the benefits of this merger for Texas ratepayers and to ensure that the merger is in the public interest.

2. Houston Industries, Inc.'s Acquisition of NorAm

This merger is between Houston Industries (HI), the parent company of Houston Lighting and Power Company (HL&P), and NorAm, a natural gas company. Vertical mergers are sometimes referred to as convergence mergers.

The two Texas utilities involved in this merger, HL&P (an electric utility) and Entex (a gas utility), have service territories that overlap in the Houston metropolitan area. They have approximately 600,000 retail customers in common. HL&P supplies virtually all retail electricity and Entex generally provides all retail natural gas sales to domestic (residential and commercial) customers in the common area. Entex provides only a small percentage of sales to large gas users in the overlapping area.

Unlike the SPS/PSCo merger, the Commission had no jurisdiction to approve the Houston Industries/NorAm merger. The Federal Energy Regulatory Commission (FERC), on the other hand, did have authority to review and approve the merger, which it approved in an Order issued July 30, 1997.[18] With respect to competitive issues, the FERC concluded that "it is unlikely that the proposed disposition of NorAm's facilities will create or enhance horizontal or vertical market power in the most relevant market, i.e., the wholesale generation market within ERCOT."[19]

Vertical market power analyses focus on the relationship between upstream markets for transportation of natural gas, which is used as a fuel to generate electricity, and

[18] *NorAm Energy Services, Inc.* (Docket Numbers EC97-24-000 and ER94-1247-010.). Order Approving Disposition of Jurisdictional Facilities and Accepting for Filing Code of Conduct, Modified. Issued July 30, 1997.

[19] *Id.* at 2.

downstream markets for that power. A vertical merger may result in efficiencies from combining input (gas) and output (electricity) operations. It may, however, give the merged firm incentive to use its market position in one segment of its operations to adversely affect competition in a related segment of its business.

Vertical mergers raise three potential problems: (1) denial of input to rivals of the merged firm, (2) increased anticompetitive coordination, and (3) evasion of regulation. These actions can affect competition through higher prices or reduced output in the downstream market. The FERC determined that the upstream market is deliverable gas and the downstream market is wholesale electric energy and capacity. The FERC focused its analysis only on whether the merged firm could deny its rivals the delivery of gas. The concern is that the market for electricity could be affected by the exercise of market power in the upstream market, delivered gas.

The FERC adopted NorAm's analysis of competitive conditions in the delivered gas market. NorAm argued that the gas market in the Houston area is very competitive and entry is easy. Therefore, NorAm cannot profitably deny access to or raise the cost of delivered gas to new gas-fired generators that compete with the merged company. The FERC, therefore, concluded that NorAm cannot exercise market power in the relevant upstream market; consequently, the merged company will not be able to exercise market power in the relevant downstream market for electric energy and capacity.

In the retail market, the FERC concluded that the consolidation of HL&P's retail franchise with Entex's natural gas distribution franchise will result in the merged company being able to discourage and possibly prevent the substitution of whichever fuel is most profitable to the firms interest to sell or deliver.[20] Although the FERC's conclusion about the potential impact on retail markets did not weigh in its approval of the merger, the impact on Texas is nevertheless important.

The question of whether the HL&P/NorAm merger would tend either to promote or enhance anticompetitive practices in the retail market for electricity in the overlapping

[20] *Id.* at 10.

areas served by HL&P and Entex was not a factor in the FERC decision, because the merging companies did not have to satisfy any conditions for *retail* impacts to receive regulatory approval from the FERC. Nonetheless, a regulatory gap exists when convergence mergers are proposed. PURA does not grant the Commission the authority find a merger consistent or inconsistent with the public interest when the merging companies are not both electric utilities.

3. Texas Utilities Company's Acquisition of Enserch

In a merger similar to the Houston Industries/NorAm merger, Enserch Corporation merged with Texas Utilities Company on August 5, 1997. Enserch Corporation is an integrated natural gas company with interests in natural gas distribution, transmission, storage and other energy-related services. Enserch merged with Texas Utilities Company in a transaction that included Lone Star Gas Company and Lone Star Pipeline Company, two of the largest natural gas distribution and pipeline companies in the nation. Other Enserch entities now operating as TU companies include Enserch Energy Services, a natural gas marketing firm, and Enserch Development Corporation, an independent power production company. Enserch Corporation's oil and gas exploration company, Enserch Exploration, was spun off prior to the merger. Lone Star Pipeline Company (LSP) is the 16th largest natural gas pipeline in the U.S. with over 7,700 miles of gathering and transmission lines in its Texas intrastate system and is connected to three major market centers.

TU/Enserch did not need regulatory approval from the Commission or the FERC to consummate this merger. As stated previously, the Commission has no express approval authority over convergence mergers between gas and electric utilities. Where the FERC's jurisdiction in the HL&P/NorAm case was linked to the existence of a FERC-licensed power marketing affiliate of NorAm, no such Enserch affiliate existed in this case.

4. Acquisition of Central and South West Corporation by American Electric Power

On December 22, 1997, American Electric Power Company, Inc. (AEP) and Central and South West Corporation (CSW) announced that their boards of directors approved a merger agreement creating a company with a total market capitalization of approximately $28.1 billion. This combination is designed to create a diversified electric utility serving more than 4.6 million customers in 11 states and approximately 4 million customers outside the United States.

On April 30, 1998, CSW and AEP filed an application requesting a determination that their proposed business combination is consistent with the public interest under PURA § 14.101(b). CSW and AEP state that the combination will result in non-fuel savings estimated at approximately $2 billion over a ten-year period. CSW and AEP propose those savings to be shared with customers. They also propose the customer portion of the non-fuel savings to be applied to amortization of regulatory assets or, when no such assets exist, to depreciation of distribution plant. This application is pending before the Commission, with final approval expected in 1999.

Like the SPS/PSCo merger case, the Commission has stated that the merger must satisfy the statutory requirements in PURA that govern mergers of electric utilities, as well as the standards developed in the SPS/PSCo merger.

In addition to conducting its review of the merger in Texas, the Commission has intervened in CSW's and AEP's merger proceeding before the FERC. The Commission intervened to protect the interests of the State and its ratepayers. In particular, the commission stated in its notice of intervention in the FERC proceeding that the following three areas warranted consideration by the FERC in its review of the proposed merger:

- a commitment by the Applicants to join appropriate transmission control groups governed by independent system operators;
- a commitment by the Applicants for clear and unambiguous authority for state commissions to review non-energy affiliate transactions; and
- clarification of certain allocation methodologies in their proposed system agreements.

D. DISCOUNTED RATES

1. Investor-Owned Utilities

Discounted rates are rates offered by utilities that are less than the fully allocated cost-of-service-based rate. Generally, such rates are offered to customers that have one or more realistic alternatives for the provision of electric service, including the traditional electric provider. Examples of these options include customers with expiring wholesale contracts, customers with cogeneration or self-generation options, and customers located in multiply-certificated service areas, among others. Discounted rates may also be offered for the stated purpose of economic development. A review of the Commission's actions regarding discounted rate offerings is contained in Chapter V.B.3.f of the 1997 Scope of Competition Report. In that report, the Commission noted as follows:[21]

> Wholesale and retail discounted rates are governed by §§ 2.001(b) and 2.052(b) of PURA95, which state:
>
> *On application by a public utility, the regulatory authority may approve [wholesale or retail] tariffs or contracts containing charges that are less than rates approved by the regulatory authority but equal to or greater than the utility's marginal cost.*
>
> In addition, PURA95 contains additional safeguards to ensure that the discount is not financed by other utility customers. Specifically, PURA95 §2.001(d) states:
>
> *Notwithstanding any other provision of this Act, the commission shall ensure that the utility's allocable costs of serving customers paying discounted rates under this section or Section 2.052 of this Act are not borne by the utility's other customers.*[22]

[21] 1997 Scope of Competition Report, Chapter V-38.

[22] Following the codification of the Public Utility Regulatory Act in 1997, PURA95 §§ 2.001(b) and 2.052(b) now exist together in PURA § 36.007(a); PURA95 §2.001(d) is now PURA §36.007(d). Because this section refers to the 1997 Scope of Competition Report, which references PURA95, all references in this section to discounted rate provisions use the PURA95 citations rather than current Utilities Code references in an effort to maintain consistency and avoid confusion.

Also in the 1997 Scope of Competition Report, the Commission included the following finding of fact from Docket No. 14716[23] relating to the application of PURA95 § 2.001(d):

> *Section 2.001 of PURA requires that the Commission ensure that the allocable costs of serving customers paying discounted rates are not borne by the utility's other customers. The Commission's interpretation of this requirement . . . is that "allocable costs" refers to embedded costs, rather than marginal costs. This interpretation is supported by the Commission's conclusions that requiring the utility to bear the fully embedded costs is necessary to (a) preclude costs of serving discounted customers from being shifted to other customers and (b) limit a utility's ability to subsidize its activities in a competitive market with revenue from a captive market.*[24]

In addition to voluntary discounted rates, PURA § 36.351(a) requires that each electric utility and municipally owned utility provide a 20 percent reduction of the utility's base rates for electric service provided to a facility of a four-year state university, upper-level institution, Texas State Technical College, or college. PURA § 36.351(f) states that an investor-owned utility may not recover from residential customers or any other customer class the assigned and allocated costs of serving a state university or college receiving such a discount.

Subsequent to the submission of the 1997 Scope of Competition Report, the Commission addressed the rate treatment of discounted rates for investor-owned utilities on the following four occasions:

- **HL&P Transition Plan**:[25] Adjusted HL&P's allowed rate of return downward from 9.95 percent to 9.844 percent as a proxy for the imputed revenue attributable to the HL&P's discounted rates.
- **TU Electric Transition Plan**:[26] Included a direct revenue imputation of $16,092,163 to account for the existence of discounted rates.
- **TNP Transition Plan**:[27] Included a direct revenue imputation of $4,118,353 to account for the existence of discounted rates.

[23] *Application of Texas Utilities Electric Company for Authority to Implement Rate WP1 to Lyntegar Electric Cooperative, Inc. and Taylor Electric Cooperative, Inc.,* Docket No. 14716, Final Order (March 21, 1996).

[24] *Id.,* Finding of Fact No. 56A.

[25] Docket No. 18465, Order on Rehearing, Finding of Fact No. 48C and Conclusion of Law No. 10.

[26] Docket No. 18490, Order on Rehearing, Findings of Fact Nos. 65-68 and Conclusion of Law No. 12.

- **Entergy Rate Case**:[28] Included a direct revenue imputation of $8,483,000 million to account for the existence of discounted rates.

In each of these cases, the Commission's determination regarding the treatment of discounted rates carried out the directives of PURA §§ 36.007(d) and 36.351(f). That is, the Commission's actions served to ensure that allocable costs of serving customers paying discounted rates are borne by the utility's shareholders, rather than its other customers.

2. Electric Distribution Cooperatives

In 1995, new legislation was enacted allowing retail electric distribution cooperatives to become deregulated for ratemaking purposes upon a majority vote of its members. As of September 1998, 60 of the distribution cooperatives in the State (approximately 75 percent) had been certified by the Commission to be deregulated for ratemaking purposes.

Also in 1995, the Legislature provided rate deregulated cooperatives the ability to "adopt retail tariffs or contracts containing charges that are less than the average embedded cost rates but that are not less than the electric cooperative's marginal cost" (discounted rates).[29] Unlike investor-owned utilities that are owned by shareholders, electric cooperatives are owned by their members. The Legislature recognized this distinction by providing an exception to the strict cost-shifting prohibitions contained in PURA95 § 2.001(d) for rate deregulated cooperatives.

In its initial determination in 1996 regarding the applicability of the cost-shifting prohibition of PURA to deregulated cooperatives, the Commission concluded that the identical standards applicable to rate regulated utilities were applicable to deregulated

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[27] *Application of Texas-New Mexico Power Company for Approval of Transition Plan and Statement of Intent to Decrease Rates*, Docket No. 17751, Order on Rehearing, Finding of Fact No. 46 and Conclusion of Law No. 11 (Date).

[28] *Application of Entergy Texas for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Under-Recovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at Schedule KS-J3 (Oct. 14, 1998).

[29] PURA §36.306(a) (formerly PURA95 §2.2011(p)).

cooperatives.[30] However, in a subsequent ruling, the Commission concluded that it was not the intent of the Legislature to apply the strict cost-shifting standards applicable to rate regulated utilities to rate deregulated cooperatives.[31] This reversal was based upon the Commission's conclusion that application of the cost-shifting prohibitions contained in PURA95 § 2.001(d) to rate deregulated cooperatives would conflict with the express language of PURA95 § 2.2011(p) that allows rate deregulated cooperatives to offer discounts as low as marginal cost. Thus, because application of the cost-shifting standards to rate deregulated cooperatives would thwart the clear intent of PURA95 § 2.2011(p), and because PURA95 § 2.001(d), which contains the cost-shifting prohibition, does not expressly override PURA95 § 2.2011(p), the Commission reversed its initial decision.

While the Commission has recognized the legislative intent to allow rate deregulated cooperatives to offer discounted rates to retail customers, it remains concerned with the use of this tool by some cooperatives to offer discounted electric service to only select customers, rather than to the membership as a whole.

In the two years covered by this report, the number of cooperatives adopting special "pass-through" tariffs has continued to grow, although data is not available indicating how many customers are actually being served under the special tariffs for each deregulated cooperative, if any.

While rate-deregulated cooperatives may change rates on their own motion, they must comply with the filing and notice requirements as set forth in PURA §§ 36.301-309 before the proposed rates are effective. Examination of the rate changes effected by deregulated cooperatives in 21 dockets indicates that, on average, rates for residential customers were *increased* by approximately 2.9 percent, whereas rates for large commercial and industrial customers were *decreased* by approximately 2.1 percent.[32]

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[30] *See* 1997 Scope of Competition Report at Chapter V-40 to 42.

[31] *Petition for Authority and Statement of Intent of Sam Rayburn G&T Electric Cooperative, Inc. to Extend and Modify Economic Development Rate Through December 31, 2000*, Docket No. 16620, Final Order (Date).

[32] The Docket Nos. of these cases are: 15018, 15212, 15323, 16270, 16351, 16619, 16683, 16714, 17095, 17288, 17540, 17613, 18430, 18727, 18767, 18864, 18990, 19111, 19267, 19457, and 19771. Average values are

Large commercial and industrial customers fared better than residential customers in 18 of the 21 dockets analyzed.

This is not to say that cooperatives have not taken advantage of opportunities presented by the increasingly competitive wholesale market to provide rate reductions to their membership as a whole—many have. However, similar to discounted rates offered by IOUs, the Commission remains concerned with the application of select rate discounting and the effect that it may have on the rates of other utility customers.

E. Interruptible Rates

A number of utilities have in place "interruptible service" (IS) tariffs or tariff riders that allow those utilities to interrupt service temporarily to specific, generally large industrial customers. These interruptions occur typically during times of high demand or equipment outages when there is insufficient capacity to serve both the utility's firm (non-interruptible) loads and the utility's interruptible loads. In return for the right to interrupt a customer, the utility offers to IS customers a rate that is less than the firm rate the customers would otherwise pay for firm service. Unlike discounted rates, the difference is not borne by utility shareholders.

Historically, IS rates have been set either at a reduced percentage of the otherwise applicable firm demand charges (*i.e.*, credit method) or at a level designed to recover the as-incurred costs to provide interruptible service, including a contribution to fixed costs (*i.e.*, actual cost method). Under the credit method, an IS customer who agrees to be interrupted at any time without prior notice may receive a credit ranging from 35 to 100 percent of the firm demand charge that would otherwise apply. In some cases, fixed costs are also recovered from these customers in the energy charge those customers pay. A customer that requires some period of prior notice (*e.g.*, a "five-minute" or "thirty-minute" prior notice IS customer) would receive a lesser reduction in the demand charges. These reduced demand charges apply irrespective of the length and number of actual interruptions during a year. This is because the utility

calculated as a simple average of the percentage rate change for the residential and the large commercial/industrial customer classes in each docket.

does not plan to meet the needs of those customers, and the IS customer must incur costs to qualify for service and stand ready to respond to an interruption request at any time it is called upon by the utility. Under the actual cost method, the as-incurred costs fluctuate with fuel prices, which are typically based upon the price of natural gas. Minimum demand charges may also apply, and the customer is required to schedule load in advance. The customer is then charged for the greater of actual or scheduled load.

Interruptible service benefits the interruptible customer because the customer can achieve significant rate reductions, and thereby reduce its overall electricity costs. A large industrial customer could decide that it is worth being interrupted from time to time if it gains sufficient price concessions by agreeing to sign up for interruptible service. Interruptible service is also beneficial to the utility and to firm customers because it serves as a demand side resource that allows the utility to avoid acquiring new generation or transmission capacity to the extent it can curtail interruptible loads during periods of high demand. With IS service in place, the utility will interrupt all of its IS customers before it would be compelled to curtail service to firm customers. Also, because IS can be viewed as a resource, it may not be necessary to the utility to install as much generation capacity as it would if it served only firm loads, which serves to help reduce costs for all firm customers.

Since the last legislative session, the Commission has begun to revise its policy regarding interruptible service. The Commission now prefers to treat IS as a true demand side resource that should be bid into a utility's integrated resource planning (IRP) process. Historically, the Commission would authorize a set rate or discount applicable to interruptible service, and the utility would sign up any interested, qualified customer. Starting with the CPL rate case (Docket No. 14965), and continuing with the EGS rate/transition case (Docket No. 16705), the Commission now requires that the current tariff/contract-based IS will be terminated after a transition period, to be replaced with an IRP/bid-based interruptible service.

Specifically in the CPL rate case, the Commission concluded that, while the interruptible rate is not a "discounted rate", *per se*, CPL's interruptible rates may be oversubscribed and underpriced. The evidence suggested that CPL's primary motivation in offering interruptible service and in setting interruptible rates was to retain large industrial customers, who could have met their energy needs by generating their own power at a cost that would be lower than the CPL firm rate. In the context of a more competitive market, the Commission concluded that interruptible service and rates should be based on both (1) a clear definition of CPL's resource need and how this service meets that need; and (2) a market-based assessment of the value of interruptible service. Accordingly, the Commission closed the CPL interruptible rates to new customers, and directed that a process be developed in which the value of interruptibility can be determined using a market mechanism.[33] The same rationale applied in the EGS rate/transition case. The market based mechanism adopted in both cases involves the utilities' IRP process.

Through the IRP process, and in the context of interruptible service, market forces rather than regulatory/cost of service considerations prevail because the utility is required to solicit resource bids for IS from any interested customer/provider. First, the utility will determine how much additional capacity it will need during the next three to five (or more) years. Resources to meet that additional need will be solicited from both the supply side (that is, those who will sell (supply) power to the utility) and from the demand side (that is, those who will take action to reduce the need for electricity). Through the bidding process, the utility, subject to Commission review and approval, will determine an appropriate mix of supply and demand side resources. As to interruptible customers, the customer(s) willing to be interrupted for the least discount off that customer's firm price will likely win the IS demand side resource contract.[34] This market-based determination is referred to as "pricing" the interruptible resource. The utility and Commission will also take into account the amount of interruptible capacity bid into the solicitation. This market-based

[33] In some instances, however, the Commission has found that requiring customers to bid a demand-side resource contract is not feasible or desirable. For example, in the CPL case, the Commission instead approved a new interruptible tariff that was designed to capture the market value of interruptible service.

[34] Price is a major factor, but it is not the only consideration in determining who wins the bid. The amount of interruptible capacity, transmission constraints, and length of prior notice required by the bidding customer will also be factored into who wins the IS portion of the solicitation.

determination of the amount of interruptible capacity available to a utility is referred to as the "sizing" of the interruptible resource. In conclusion, through the IRP process, the Commission anticipates that the use of interruptible service will more closely match the actual resource needs of the utility, while ensuring that the utility's costs are kept to the lowest possible reasonable level.

F. TRANSMISSION ISSUES

The principal function of the transmission system is as a transportation network. The ability of buyers and sellers of power to use a transmission system to move power from one place to another is related to the physical capability of the network, their rights of access and use, and the costs of using it. In principle, a transmission network is like other transportation networks, such as a road system or gas pipeline system, and the issues for users are the same: the physical size of the network, rights of access, and cost. The State of Texas and the federal government have mandated that the transmission systems in Texas and the rest of the country be accessible to persons other than their owners for the delivery of power in the wholesale market. They have also supervised the development of prices for the use of the transmission systems by third parties.

1. Jurisdiction

Both the FERC and the Commission have required utilities to provide access to others on terms that are comparable to the use that the utilities themselves make of the transmission system. There are, however, important differences in policies and practices that have made the open-access policy less effective in the areas where the FERC regulates wholesale transactions than in areas subject to the Commission's regulation. The key differences between the FERC-regulated areas and the Commission-regulated areas are different pricing methods and the establishment of an independent system operator to serve as the gatekeeper for the transmission system. The Commission has prescribed a regional pricing system for the intrastate electrical network in Texas (Electric Reliability Council of Texas, or ERCOT) that is intended to foster competition among generators, by eliminating transmission costs as a factor in the daily and hourly decisions that each utility makes in selecting which power plants to use to meet its customers' needs. The FERC pricing mechanism, on the other hand, permits transmission owners to set rates on an individual, rather than regional, basis and to include transmission costs in rates in such a way that they *are* a factor in selecting the power plants to use to meet customers' needs. The FERC pricing mechanism is less effective in fostering robust competition among generators.

In ERCOT, the Commission established an independent system operator (ISO) to serve as a gatekeeper for the transmission system. The ISO is governed by three representatives from each of six wholesale stakeholder market segments. This neutral gatekeeper helps make the policy of non-discriminatory access a reality, by taking the access decision out of the hands of one of the competitors in the market. The ISO in ERCOT also plays a role in planning new transmission facilities, facilitating the development of the network in a way that does not favor either utility or non-utility interests. While the FERC has encouraged the development of ISOs in other regions, it has not required utilities to form or join ISOs. The ISO is an important feature that fosters wholesale competition, but the prospects for developing ISOs in Texas outside of ERCOT are uncertain.

Establishing third-party access rights has resulted in increased use of the ERCOT transmission network. Growth in demand for electricity and state policies favoring wholesale competition have also resulted in the planning and construction of new, non-utility power plants that need to use the transmission system to deliver power to their customers. The increased use has, in some instances, taxed the capability of the existing transmission infrastructure.

Within ERCOT, circumstances are conducive to upgrading the transmission infrastructure and to revising the terms of access and prices for its use, as needed to foster competition and meet the demands of a more competitive wholesale environment. The factors that support this optimistic assessment are the existing cooperative relationships among transmission owners and users, clear state policy favoring wholesale competition, the existence of an ISO, and the Commission's broad authority over wholesale and retail matters. Outside of ERCOT, the prospects are less favorable, as transmission owners and users seek transmission rules that provide them a competitive advantage and the regulators' ability to deal with competitive issues is hamstrung because authority is divided among a number of states and the federal government.

2. Overview of the Texas Transmission Grids

The electrical network in the United States is divided into three Interconnections:[35] the Western Interconnection, the Eastern Interconnection, and ERCOT. ERCOT is connected with the Eastern Interconnection by means of two direct-current (DC) ties with a combined capacity of 820 megawatts. This represents less than 2 percent of the peak load in ERCOT. The Eastern and Western Interconnections are also connected to each other through DC ties. Two of these DC ties are located in Southern New Mexico and connect Southwestern Public Service Company (in the Texas Panhandle) with the utilities in New Mexico and the El Paso area. There are no direct connections between ERCOT and the Western Interconnection. There are limited interconnections between the Western Interconnection and the electric utility network in Mexico at El Paso and between ERCOT and Mexico in the lower Rio Grande Valley.

The ERCOT transmission network is located entirely within Texas and is, for the most part, subject to the wholesale jurisdiction of the Commission. The transmission facilities located in the non-ERCOT regions of Texas are subject to the wholesale jurisdiction of the FERC. The large transmission-owning utilities that provide service in the non-ERCOT regions of Texas also provide retail service in neighboring states and are subject to retail regulation by the authorities of those states as well as the Commission.

[35] Interconnections consist of a number of individual utility systems that are connected to each other and normally operate synchronously. That is, all of the generators in the system are connected by transmission lines and the alternating current they produce is synchronized.

The map in Figure 1 shows the three interconnections and the reliability councils in each. ERCOT covers most of the State, accounting for approximately 80 percent of

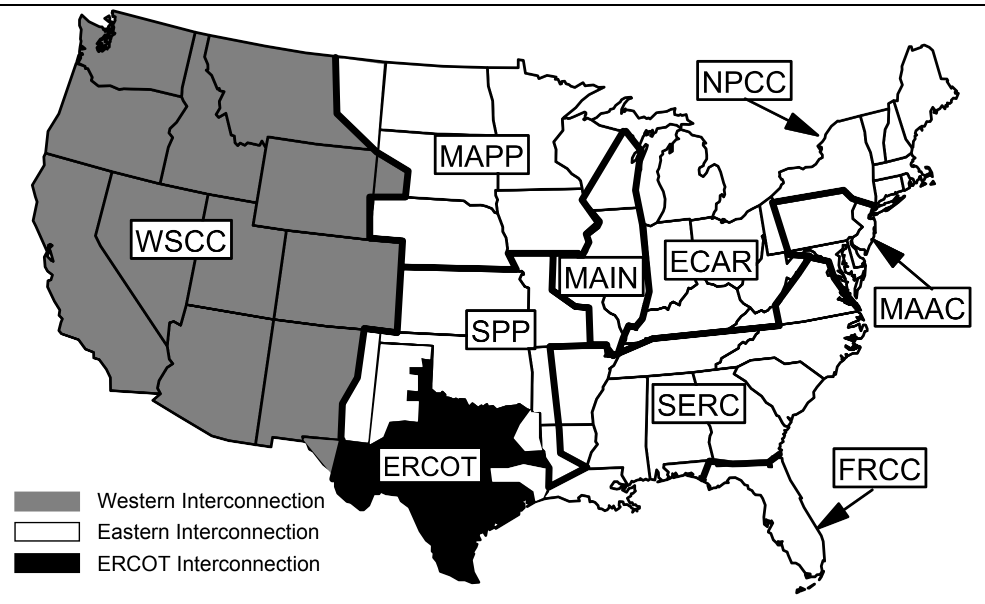

Figure 1 - U.S. Interconnected Transmission Systems

the electricity generated in Texas. The reliability council in the Western Interconnection is the Western System Coordinating Council (WSCC). The reliability councils in the Eastern Interconnection that have customers in Texas are the Southwest Power Pool (SPP) and Southeastern Electric Reliability Council (SERC).

The transmission system consists of facilities that are used to transmit power at high voltage levels from generating plants to substations, the points where the voltage level is reduced for distribution to retail customers. The transmission system is an interconnected "highway" that allows for the bulk transportation of electricity that serves millions of customers. While the transmission system's primary function is to transport electricity, it is also a key element in providing continuous, reliable service to customers. In contrast to outages at individual generating units (which may have ready substitute resources) or problems on a distribution system (which may have rather localized effects), transmission outages have the potential to disrupt electric service over a large geographic area.

In the regulated environment of the past, vertically-integrated utilities constructed transmission facilities to provide reliable delivery of electric power from their generating plants to their native load (retail customers and wholesale customers under contract). In addition, utilities recognized they could achieve reliability and economic benefits by constructing transmission interconnections with neighboring utilities. The need for such interconnections was particularly pronounced in ERCOT in the late 1970's and 1980's with the construction of large coal or nuclear generating facilities by most of the large utilities in the region. During this period, additional transmission interconnections were constructed to enhance system reliability through sharing of generation reserves and the use of multiple transmission paths from generators to customers. The result is an interconnected network in ERCOT of transmission facilities that not only permits utilities to transport electricity to their native load customers, but also allows them to make economic exchanges of electricity with other utilities and non-utility producers. Thus, the transmission system is an integral component of the increasingly competitive wholesale market. Adequate transmission capacity and appropriate access and pricing policies help to promote a vibrant wholesale market, which provides benefits to both suppliers and customers.

3. Transmission Pricing and Access—Promoting Wholesale Competition

In the ERCOT region of Texas, the Commission has jurisdiction to establish rates, terms and conditions for wholesale transmission service. In 1995, the Legislature enacted provisions of the Public Utility Regulatory Act requiring the Commission to establish open-access transmission service to promote competition in the wholesale market.[36] In response to this legislative mandate, the Commission adopted P.U.C. SUBST. R. 23.67 (Open-access Comparable Transmission Service) and 23.70 (Terms and Conditions of Open-access Comparable Transmission Service) in February 1996. The Commission and FERC rules are designed to remove impediments to third-party access to the transmission system and encourage increased competition in wholesale power markets. Because of differences in their legal authority and different policy

[36] These provisions now appear in §§35.001-35.008 of the Texas Utilities Code (Vernon 1998).

perspectives, the Commission and the FERC adopted rules that are different in significant respects. One of the differences is in pricing of transmission service.

In April 1996, the FERC issued a transmission access rule, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (Order No. 888).[37] Order No. 888 requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file tariffs to provide open-access, non-discriminatory transmission service. The FERC's goal was "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, low cost power to the Nation's electricity consumers."

a) Transmission Pricing

The Commission adopted a uniform transmission pricing system for ERCOT that has two key features: it permits access to all of the transmission facilities in ERCOT at a single price, and it prices short-term service at low rates to encourage short-term purchases and sales. A user of the transmission system pays the fixed costs of the transmission network up front, and the cost of using the network on a day-to-day basis is limited to the cost of transmission losses, that is the "fuel cost" of moving power from one point to another.[38] The magnitude of the loss charges is much smaller than rates that include fixed costs. The ERCOT pricing method was adopted in the expectation that it would lead to vigorous competition between producers on the basis of the price of power, and ultimately to lower prices for customers in Texas.

For the most part, the FERC has permitted transmission rates to be developed on a utility-by-utility basis, and has permitted all transmission users to be charged usage fees that include the fixed costs of the transmission systems. While the FERC has encouraged regional pricing methods, the transmission rates that have developed in

[37] 61 Fed. Reg. 21,540 (1996).

[38] When electricity is transmitted over a conductor, part of it is converted to heat and does not reach the appliance that is powered by the electricity. The lost energy is referred to as transmission losses, and additional fuel must be consumed in the generator to make up for the losses.

most areas of the country are utility-by-utility rates. The resulting rates impede the development of robust competitive markets. The differences in the ERCOT transmission rates and the typical FERC-approved rates may be illustrated by analogy to a road system. The ERCOT transmission pricing system works like the tax assessments that cover the cost of the road network, where the fixed costs of the transportation network are not included in the daily and hourly fees for using the system. (Using the road analogy, tomatoes can be delivered to Dallas from California, South Texas, or Florida for the cost of the fuel used in the truck that delivers them, so there is competition among producers that benefits Dallas customers.) The FERC rates are like the tolls on a toll road, where fixed costs are included in mileage-based tolls. The FERC pricing system stifles long-distance trades in electricity, because the delivered cost of the power ultimately includes the "tolls" charged by each of the utilities between the producer of the power and the user. (In the road analogy, tolls would be collected every 100 miles, for example, and the number of producers of tomatoes that could compete to sell in Dallas would be limited.)

In 1995 the Legislature directed the appointment of a committee to analyze the costs and benefits of building synchronous interconnections between ERCOT and the SPP. The committee evaluated the potential for trades between ERCOT and the SPP, under a number of different scenarios, including a scenario in which the transmission rates in the SPP and adjacent areas were modified to reflect the ERCOT pricing method. This committee's report supports the conclusion that simply revising the transmission rates outside of ERCOT to match the pricing method within ERCOT would lead to significant additional trading between the two areas, and within the SPP, and significant reductions in total production costs for the two areas.[39] In other words, the ERCOT transmission pricing method, if applied in the SPP, would lead to increased competition among generators and lower power costs.

In the areas of Texas outside of ERCOT, utility-by-utility transmission tariffs that include full transmission costs are the norm. In the SPP, an area that includes

[39] *Report to the 76th Legislature: Feasibility Investigation for AC Interconnection between ERCOT and SPP/SERC*, Synchronous Interconnection Committee, at 6-23 through 6-26 (Draft Report, August 1998).

northeast Texas and the Panhandle region, a regional tariff was proposed by many of the utilities in the region and was approved by the FERC. This is an incomplete pricing reform, however, because SPP utilities can opt out of the regional tariff, and short-term sales may still be burdened by fixed costs (One of the utilities that opted out of the tariff was Southwestern Public Service Company, which serves Amarillo and the Panhandle. Entergy, which serves Beaumont and Southeast Texas, was a member of the SPP but withdrew from membership during the course of the efforts in the SPP to develop a regional tariff and an ISO and joined the SERC. No effort is currently under way to develop a regional tariff in the SERC). In the southern WSCC, including the El Paso area, efforts are under way to develop an ISO (Desert Star) and regional transmission tariff. The Desert Star efforts appear promising, although they have not yet come to fruition.

There are a number of impediments to the revision of transmission pricing methods, including different interests between integrated utilities and non-utility producers, and policy differences among state regulators and the FERC. In general, in the areas where the FERC has authority to regulate wholesale transactions, regulatory authority is divided among a number of state regulatory commissions and the FERC, making it difficult for regulators to reach a consensus and easier for the large, integrated utilities to impede the adoption of measures that would foster competition. Also, FERC authority does not extend to public power/municipal systems—a major jurisdictional hole which the Texas Legislature successfully avoided in 1995.

b) Transmission Access

In ERCOT, the ISO serves as a gatekeeper for the transmission system, and plays a key role in ensuring that the policy of non-discriminatory access is a reality. Transmission access decisions are made by the ISO, rather than by a utility that is also one of the competitors in the market. Other responsibilities of the ISO include: (a) ensuring the reliable operation of the bulk electric system (the transmission network) and (b) coordinating transmission planning for the ERCOT region.

In areas where there is no ISO, contentious issues have arisen between power producers and transmission owners over the amount of transmission capacity that is available to third parties and who has the right to use the transmission system when high customer demand loads the network to its capacity. Non-owners using the transmission systems have complained that the transmission service they receive is not comparable to the service the owners receive in areas without an ISO. The reality or perception of a lower level of service that buyers and sellers of power obtain when they rely on the FERC-approved transmission tariffs impairs their confidence in the wholesale market. Issues concerning comparability of service are likely to arise in any region of the country, but buyers and sellers of power have greater confidence in the decisions of a neutral expert than in the decisions of a competing integrated utility. As a consequence, non-utility power producers are more likely to invest in new production facilities in areas with an ISO, thereby leading to a more competitive market.

While the FERC has encouraged the development of ISOs in other regions, questions about its legal authority to require ISOs have deterred it from doing so. The Commission has filed comments in FERC proceedings encouraging the development of ISOs, particularly in the areas north and east of ERCOT that would affect transmission access to the SPP areas of Texas. As is noted above, there are ISOs under consideration in the southern WSCC and in the SPP, but not in SERC.

4. Impact of Open Access on Wholesale Power Markets

Around the country, the ownership of generating facilities has been highly concentrated in regulated public utilities. This concentration was reduced to some degree in the 1980's by the development of qualifying cogenerators, encouraged by a federal statute.[40] Later, independent power projects were developed in some states to sell power at wholesale to electric utilities. The introduction of competition in California and other states has resulted in significant non-utility generation, either through the sale of existing facilities by utilities to merchant power suppliers or the

[40] Public Utility Regulatory Policies Act of 1978, 16 U.S.C.A. §§ 2601-2645 (West 1985 & supp. 1997) (PURPA).

construction of new facilities by merchant suppliers. In California and New England, restructuring has resulted in the sale of over 17,000 megawatts of utility generating facilities to new market entrants. Projects for the construction of over 10,000 megawatts of merchant power are in the planning or construction phases in these areas. The reduction in market concentration in generation is an essential condition for vibrant competition in a retail or wholesale market, and in California and New England it is being achieved by sale of existing generating facilities and the construction of new facilities by merchant power suppliers. In Texas, there have not been any sales of utility facilities, but about 1,000 megawatts of non-utility generation has changed hands, and roughly 10,000 megawatts of merchant power is in the planning or construction phase. Most of this activity is in ERCOT.

The development of new merchant power projects outside of Texas appears to be a consequence of the introduction of retail competition. Developers appear to have concluded that new projects can compete with existing facilities and are committing billions of dollars on new facilities to begin to compete. A developer's decision to build a new generating plant is, of course, strongly influenced by economic factors, such as the existing supply-demand relationship in a market, the prospects of growth in the demand for electricity, and the relative production costs of new and old generation facilities. Nonetheless, the adoption of retail competition under rules that give new market entrants a reasonable opportunity to compete with existing service providers has been a significant factor in merchant power-plant development activities. Texas has also experienced a significant level of merchant power activity, and it appears that access to a broad wholesale market on equitable terms coupled with the expectation of retail choice have been key factors in spurring this activity.

Prior to the adoption of open-access transmission rules, most short-term energy trading in Texas took place between four investor-owned utilities and 14 municipal utilities and cooperatives. Since the opening of the wholesale market to competition, 33 independent power producers and power marketers have joined the 18 original participants. The power marketers and independent power producers have had an increased presence in the wholesale market since it was opened to competition.

However, despite the increased participation of power marketers and independent power producers, most observers regard the short-term market as relatively thin; it constitutes roughly 5 percent of the annual energy sales in ERCOT.[41] A more detailed account of the status of the competitive wholesale market in ERCOT is presented in Section II.G.

5. Need for Additional Transmission Facilities in Texas

In an increasingly competitive wholesale environment, the physical power flows on the transmission system are likely to change. As a wholesale customer switches from its current utility supplier to a different utility or a non-utility supplier, and as producers and customers engage in short-term energy trading, the generating plants that are used will be different from the ones that were used in an environment in which transmission access was not assured. As a consequence, the physical flows of power will change to some degree. In addition, where new generating plants are built and operated, the new plants will change the physical flow of power in the transmission system. The new non-utility generating plants plan to compete with the existing integrated utilities for sales, and one of the challenges for regulators is ensuring that the integrated utilities plan and build new transmission facilities in a non-discriminatory fashion, so that developers of non-utility plants have a fair opportunity to compete in the wholesale market.

In areas where the transmission system is at or near its capacity limits, the new physical flows may manifest themselves as transmission constraints; that is, limitations on the capability to move power from one area to another. The ERCOT ISO identified seven significant transmission constraints in the ERCOT transmission system for the 1998 peak season.[42] The ISO indicated that the transmission system in ERCOT is currently reliable, but that constraints exist in the transmission system that,

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[41] *Investigation Into The Competitiveness Of The Wholesale Market: Final Report,* Texas Public Utility Commission (May 1998).

[42] The ISO identified the following constraints: (1) exports to the Lower Rio Grande Valley, (2) transfers into the Corpus Christi area and points south of the city, (3) transfers from the San Antonio area to the Houston area, (4) exports to West Texas, (5) imports from West Texas, (6) imports from Northeast Texas (East DC Tie - Monticello area), and (7) transfers from South Texas to North Texas.

at times, limit the ability of buyers and sellers to engage in transactions that would reduce costs to customers or provide additional revenue to producers.

Despite these constraints, the ISO expressed the belief that ERCOT loads could be served in a reliable manner over the 1998 peak period. This belief proved accurate. Despite extremely hot temperatures and record consumption in ERCOT, the power supply in the region in 1998 was highly reliable. There were non-localized disruptions to the service of firm-service customers on only two occasions, both involving one of the identified constrained areas (service into the Rio Grande Valley).

The ISO has initiated a process to identify transmission projects that would relieve these constraints and evaluate the costs and benefits of these projects. The Commission believes that the ERCOT network can evolve to support a more competitive wholesale generation market if measures are taken to alleviate the identified transmission constraints. It is expected that the ISO will continue to supervise transmission planning, and the Commission will maintain regulatory oversight over the ISO and transmission owners. Under this structure, transmission constraints can be addressed through the normal regulatory process, while relying upon market-based solutions to the extent possible. The ERCOT area also represents a large electrical market (including Houston, Dallas, Fort Worth, San Antonio, and Corpus Christi) in a relatively small geographic area. It seems likely that the enhancements to the transmission needed to alleviate the constraints will be economical, in view of the large market that the ERCOT transmission system serves.

6. Transmission Planning

Another issue that has arisen in the early stages of wholesale competition is the coordination of transmission planning with the development of a new power plant. In some states, a regulatory agency has authority to approve the site for new power plants, whether built by a utility or non-utility company. In Texas, there is no agency that has siting authority for non-utility plants. New non-utility power plants can be located wherever a developer can assemble the necessary resources (land, water, and fuel) and obtain the environmental permits. A developer may not have good information about the capability of the transmission network in an area that is otherwise suitable for development. In addition, the developer is typically unwilling to seek information from an integrated utility that owns transmission facilities, for fear of disclosing sensitive business plans to a competitor.

In supervising the transmission planning process, the ERCOT ISO has begun to receive requests for transmission service and serves as a controlled channel of communications between non-utility developers of new power plants and the utilities that own transmission systems. The existence of the ISO as a neutral gatekeeper and supervisor of transmission planning engenders greater confidence among non-utility developers that transmission needs will be identified and transmission facilities will be built in a non-discriminatory manner. The Commission is confident that mechanisms can be developed to bridge the gap between power plant planning and transmission planning, without the need for giving an agency authority to regulate the siting of non-utility power plants. Developers are still likely to encounter problems, particularly because the planning and construction of a new transmission line takes longer than the planning and construction of a new generating plant, but the existence of a neutral ISO, under the Commission's oversight, is the foundation for the development of better procedures for coordinating power plant and transmission planning.

It has been suggested that the licensing of new transmission facilities be expedited in ERCOT. If increased competition and growth in customer demand results in constraints on the transmission system, construction of new transmission facilities is likely to be required on a more timely basis. The Commission has proposed amendments to its licensing rules to expedite transmission projects, where the project is an upgrade of existing facilities or where the ISO determines that the project is important. Another proposal is to give the ISO authority to determine whether a transmission project is needed. Under current law, the Commission decides whether to license a new transmission project based on an assessment of the need for the project, its cost, and its impact on the environment and the community where it is proposed to be built (including impact on affected landowners). The issues that are usually most difficult in contested transmission cases are assessing the impacts and weighing them against the need for the facilities. Although authorizing the ISO to determine need might expedite the resolution of these issues, it may not have a significant impact in all cases, especially when landowners contest the proposed transmission project.

The non-ERCOT regions of Texas are located along the boundaries of the State in the Panhandle, the El Paso area, Northeast Texas, and Southeast Texas. There are physical limitations on the transmission systems in many of these areas. These areas are characterized by smaller electrical markets and, often, long distances between markets. These areas also lie at the electrical boundaries between Interconnections, and the lack of an ISO also makes them less attractive to potential wholesale market participants. For example, Southwestern Public Service Company, which serves Amarillo and the Texas Panhandle buys and sells electricity with the utilities in El Paso and Albuquerque, but it is connected with the utilities in these cities by long transmission lines of limited capacity. Amarillo is in the SPP, while El Paso and Albuquerque are in the WSCC. The isolated situation is similar for El Paso Electric Company. The creation of ISOs in these areas to perform transmission planning would provide a neutral supervisor of transmission planning and engender greater confidence among non-utility developers that transmission needs will be identified and facilities will be built in a non-discriminatory manner.

G. STATUS OF THE COMPETITIVE WHOLESALE MARKET IN ERCOT

The Commission Staff conducted an investigation into the status of the wholesale market during late 1997 and early 1998, including a survey of all utilities in Texas.[43] The study assesses the extent of the utilities' participation in the competitive market and updates the Commission's information on wholesale contracts. The opening of the wholesale market to competition and the implementation of unbundled transmission service have increased the number of participants and the level of short-term transactions in ERCOT (transactions of less than one year). In addition, utilities have broader purchasing options in seeking power to meet their customers' needs.

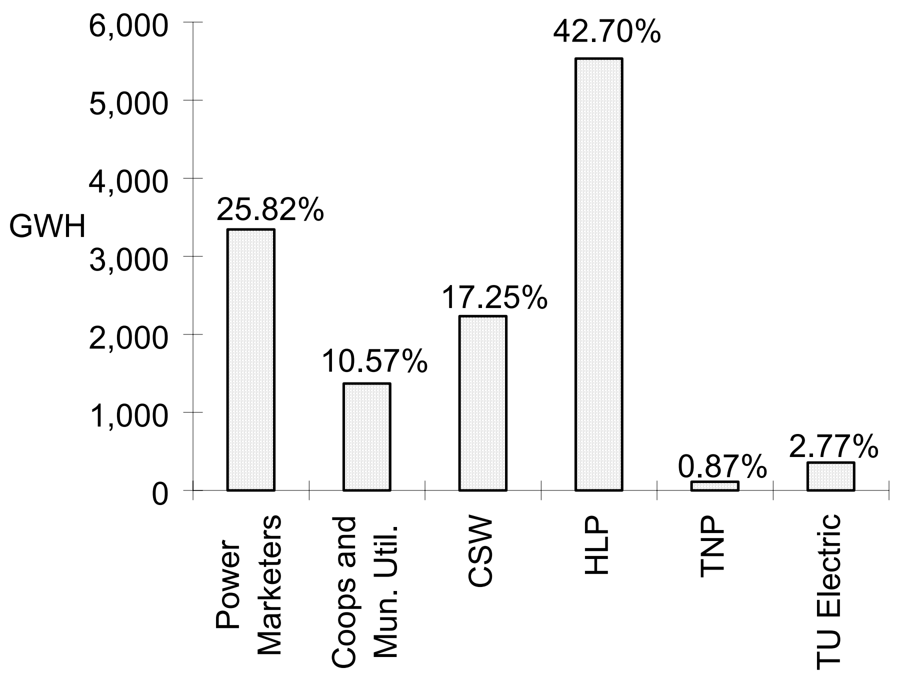

Figure 2 - January-October 1997 Short-Term Wholesale Transactions

Figure 2 shows that power marketers are responsible for a large share of the short-term electric energy trading. The data, based on January through October 1997 transactions, show the significant presence of power marketers and independent power producers in the wholesale market. However, during that interval, the total size of the short-term market was only 13,000 Gigawatt-hours (GWh), or 5.6 percent of the annual energy sales in ERCOT, which total 230,000 GWh.[44]

The level of transactions reported reflects transactions that are not directly tied to the reforms in the wholesale market, such as a joint-dispatch agreement between HL&P and City Public Service Board of San Antonio (CPS), the joint generation dispatch of the CSW companies, and sales by qualifying facilities that are mandated by Federal law. If these transactions are excluded, unplanned transactions in the ERCOT

[43] *Investigation Into the Competitiveness of the Wholesale Market*, Project No. 17555, final report (Sep. 16, 1998).

[44] ERCOT Technical Information, On-line. Available at: http://www.ercot.com/techstuf.htm. Twelve-month information indicates that total short-term transactions for 1997 were 15,000 GWh, or 7 percent of total energy sales in ERCOT during the year. Source: "Unplanned Energy Market Activities in 1997", ERCOT News p. 3, January 1998.

wholesale market in 1997 amounted to 7.8 GWh,[45] or 3.38% of annual energy sales in ERCOT.

Many participants in the competitive wholesale market have expressed concern that short-term firm power is scarce or unavailable during periods of peak demand (*i.e.*, the Summer months). During the Summer of 1998, tight generation capacity and, to a varying degree, transmission constraints limited the availability of short-term firm power during the peak periods. The lack of availability of firm power results in a "thin" market—that is, one with limited liquidity. Many wholesale market participants believe that this lack of liquidity in the wholesale market negatively affects the decisions of developers of new power plants, in that they are not receiving sound price signals concerning the need for additional generating capacity. A more liquid market would provide stronger price signals, as well as afford power producers greater opportunities to sell power or engage in hedging transactions, so as to reduce the risks of owning a power production facility.

In other areas of the country, particularly in the Midwest, wholesale markets experienced significant price spikes as a result of high demand during unusually hot weather and temporary loss of generation and transmission facilities. In Texas utilities met their commitments to firm customers, and interruptible customers experienced interruptions on several occasions. Prices in ERCOT rose at times during the summer, both in response to tight capacity in the region and high prices in neighboring markets. Presumably, both utility and non-utility producers were able to sell power to other markets on favorable terms during the price spikes.

Despite the relative lack of liquidity in ERCOT, a number of non-utility companies have announced plans to build new generating capacity in ERCOT. Table 1 lists projects that have been announced in Texas, and all but one is located in ERCOT.

[45] *Id.*

Table 1 - Announced Merchant Power Plant Projects in Texas

Company	Location	Capacity (MW)	Construction Begun (Y/N)	Region
CSW Energy	Sweeney	330	Y	ERCOT
Calpine	Pasadena	240	Y	ERCOT
Koch Power	Corpus Christi	200	N	ERCOT
Conoco	Ingleside	450	Y	ERCOT
Enron	Brownsville	50	N	ERCOT
Houston Industries	Orange County	100	Y	SERC
CSW Energy	Hidalgo County	130-500	Y	ERCOT
N1 Wind Power	Culberson County	30	N	ERCOT
Tenaska	Grimes County	830	Y	ERCOT
Calpine	Pasadena	510	N	ERCOT
LG&E	San Patricio County	300	N	ERCOT
Panda Energy	Lamar County	1,000	N	ERCOT
Panda Energy	Guadalupe County	1,000	N	ERCOT
ANP	Hidalgo County	500-1,000	N	ERCOT
ANP	Midlothian	1,000	N	ERCOT
Calpine	Hidalgo County	700	N	ERCOT
US Gen	Three Rivers	700	N	ERCOT
Power Resource Group	Lewisville	250	N	ERCOT
PacifiCorp	Grimes County	350	N	ERCOT

It appears that developers have decided to build new merchant plants in ERCOT based upon three key considerations: (1) strong load growth; (2) the expectation that the new generating technologies will produce power at a lower cost than much of the existing capacity in the region; and (3) confidence in the current competitive wholesale market, with optimism for full retail competition in the not too distant future. Merchant plants are not regulated, and they will be built only if the developers believe that they can sell power from them at a profit. The demand is manifested in the large utilities' willingness to sign contracts to purchase power for terms of up to two years, and the solicitations conducted by several smaller utilities have resulted in longer-term contracts. The developers of merchant plants also appear to be responding to the strong load growth in ERCOT and counting on the ability of their plants to be needed to meet the demand for energy beyond the term of any contracts they sign today.[46]

[46] See also *Statewide Integrated Resource Plan*, Public Utility Commission of Texas (Jan. 1999).

Although developers are planning to add significant new capacity, the thinness of the short-term market remains an issue. It is not clear, for example, whether the power plants that are being planned will be completed by the announced operating dates, and whether the amount of power added is consistent with the demand for energy. In part, the thinness of the market is a part of the "growing pains" of emerging wholesale competition, but the Commission is considering measures to encourage increased utility participation in wholesale markets. The Commission is also improving its surveillance of merchant power plant activity to better assess the magnitude and timing of generating capacity additions in the State.

Prior to changes in state law and Commission rules requiring utilities to issue solicitations for resources, large utilities usually satisfied their resource needs by building power plants rather than purchasing power. Smaller utilities were usually captive customers of a utility with generation and transmission facilities. Since the adoption of open-access rules, a number of small utilities have entered new or renegotiated contracts, relying on access to other suppliers under the transmission access rules and often conducting solicitation for resources under the Commission's IRP rules. In particular, municipal utilities and cooperatives, the smaller participants in the wholesale market, have benefited from open transmission access, by obtaining access to many more suppliers than was previously possible.

Some wholesale customers have been unable to enter into new contracts with alternative providers due to preexisting commitments. Existing contracts are a significant limiting factor in the development of a competitive wholesale market. Figure 3 demonstrates that the capacity committed through existing contracts will decline slowly over time.

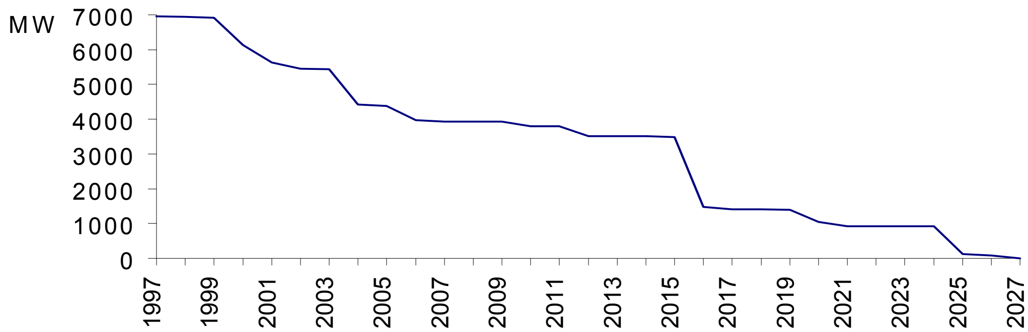

Figure 3 - Expiration of Wholesale Power Contracts in Texas

As this figure illustrates, very few wholesale purchasers are free to enter the market to buy power in the near term. One-half of the wholesale contracts in Texas have terms that extend to 2015 or beyond. Table 2 lists recently negotiated long-term wholesale supply contracts.

Table 2 - Recent Wholesale Contracts Replaced and Pending

Utility	Date and Description	Status
City of Bartlett	Signed contract with new supplier. 2 MW peak.	Complete
City of Granbury	Signed contract with new supplier for March 1996 to April 2001. Approximately 15 MW.	Complete
City of Floresville	Renegotiated a new contract in 1995 with current supplier for supply until 2015.	Complete
City of Hearne	Signed contract with new supplier for delivery beginning in April 1998. Approximately 13 MW peak.	Complete
City of Farmersville	Signed contract with new supplier. Expected peak of 6 MW.	Complete
City of Hondo	Signed a new contract with current supplier. Approximately 13 MW peak.	Complete
Cities of Denton, Garland, and Greenville	Requesting proposals that would divest them of their current generation assets. Approximately 275 MW of capacity.	Pending
City of Georgetown and DeWitt Electric Cooperative	Have selected an alternative provider for 10% of their peak requirements. Approximately 5 MW (Georgetown) and 2 MW (DeWitt).	Complete
Magic Valley Electric Cooperative	Signed contract with new non-utility supplier for 250 MW peak starting July 2001.	Complete
South Texas Electric Cooperative	Acquired a contract for four years of summer capacity from a power marketer beginning August of 1996.	Complete
Brazos Electric Power Cooperative	Signed a contract for the management of its generating assets with a power marketer.	Approval pending
Hunt-Collin Cooperative	Signed a new contract for two years beginning June 1997. Approximately 15 MW.	Complete
East Texas Electric Cooperative	Currently evaluating proposals for a start date of 2000.	Pending
Rayburn Country Electric Coop.	981,382 annual MWh	
Midwest Electric Cooperative	43,979 annual MWh	
Southwestern Electric Service Co.	410,130 annual MWh	
Texas-New Mexico Power Co.	1,128,934 annual MWh	

Even utilities with small loads such as the City of Farmersville (6 MW) and DeWitt Electric Cooperative (1.7 MW) have been able to enter the market and obtain power from alternative providers. Contracts of three- and five-year terms are most common in such cases.

One goal of the Commission's investigation into the competitiveness of the wholesale power market in Texas was to assess the degree to which market participants had experienced purchased power cost savings and the extent to which savings have been passed on to customers. In response to the Commission's survey, eight utilities reported having had power contracts that expired since deregulation of the wholesale market in 1995. Of these, five reported that negotiating a new contract with the same supplier or a contract with a new supplier resulted in cost savings for the organization. Four of the five utilities experiencing savings indicated they have adjusted rates to pass through the savings to their customers. The fifth utility used the savings to defray capital expenses and did not adjust current rates.

Southwestern Electric Service Company (SESCO), an investor-owned transmission and distribution utility that serves 42,000 customers in ten counties, completed a solicitation for its power requirements to begin in July of 1998. SESCO's customers began experiencing the lower costs of the new contract in the summer of 1998. All rate classes will see a rate decrease of approximately 28 percent as a result of the reduction in purchased power costs.[47]

East Texas Electric Cooperative (ETEC) reported savings resulting from two separate transactions. In the first, ETEC member Tex-La changed suppliers from TU Electric to WTU, resulting in excess of a 20% reduction in price from 5.5 cents/kwh to 4.2 cents/kwh. In its second transaction, ETEC entered into an agreement with Entergy Gulf States (EGS) that resulted in savings. In both cases, all savings were passed on to wholesale and ultimately retail customers through the use of the power cost recovery factors (PCRFs).

Tex-La also reports that, prior to wholesale competition in ERCOT, one of the most economical means of serving Tex-La loads in ERCOT would have been to build transmission facilities in order to connect the loads to the SWEPCO system in the Southwest Power Pool (SPP). Today, the cost of moving power in ERCOT has dropped to the point where constructing transmission facilities is not always the least-cost alternative for Tex-La. Tex-La and ETEC report that they have avoided $6 million in transmission construction costs by purchasing long-term firm power and using the existing transmission facilities of other utilities. The changes in the wholesale market have also reduced transmission charges for Tex-La.

[47] *Application of Southwestern Electric Service Company to Certify a Full Requirements Power Supply Agreement,* Docket No. 16433, Final Order (June 6, 1997).

Rayburn Country Electric Cooperative (Rayburn Country) also reported savings in its negotiation of a new contract with a power marketer, LG&E Power Marketing, that went into effect in May 1998. Rayburn Country anticipates savings in excess of $100 million over the five year life of the contract, compared to what it would pay to its former supplier, TU Electric, over that term.[48]

Most of the contracts discussed in this section were negotiated or renegotiated prior to 1998. Load growth in 1996-1998 has resulted in a tighter supply situation. The load levels experienced in 1997 and 1998 led to decisions by a number of utilities to acquire additional power resources or institute measures to reduce peak demand. It appears that the tightening of the supply situation has resulted in higher prices for power in 1998, particularly for delivery in 1999 or 2000.

The price volatility in the wholesale electric markets in the Midwest in 1998 resulted in defaults by some power marketers, significant losses by others, and the decision of a power marketing company, LG&E Power Marketing, that has been active in the Texas wholesale market to exit the market. While LG&E Power Marketing had several long-term supply contracts with municipal and cooperative utilities, it attempted to hand off its supply obligation to other suppliers or terminate its contracts with adequate notice for the customers to make other supply arrangements.

H. Commission Involvement in FERC Proceedings Addressing Competitive Issues Relating to Jurisdictional Utilities

As noted in Section II.C., with respect to the proposed CSW/AEP merger, the Commission has intervened in those companies' merger docket filed at the Federal Energy Regulatory Commission (FERC). Intervention in such federal proceedings is not new for the Commission; in the past, it has also intervened in the FERC proceedings regarding the merger application of Southwestern Public Service Company with Public Service Company of Colorado in 1996, as well as the

[48] *Application of Rayburn Country Electric Cooperative, Inc. For Certification of Power Purchase Agreement,* Docket No. 18084 (Feb. 6, 1998).

proceeding regarding the acquisition of Gulf States Utilities by Entergy Corporation in the early 1990's.

However, with the steady development and implementation of new federal policies designed to increase the level of wholesale competition throughout the nation, the Commission has identified the need to increase its level involvement in FERC proceedings that have the potential to impact utilities and customers within the State of Texas.

1. Inquiry Concerning the FERC's Policy on Independent System Operators

In its Order No. 888, the FERC established the framework for the promotion of wholesale competition in the electric industry.[49] The rules and policies embodied in Order No. 888 do not apply directly to utilities within ERCOT, but are directly applicable to Texas utilities in the non-ERCOT areas of the State. In Order No. 888, the FERC took a non-intrusive approach, requiring utilities to offer open access transmission services and to functionally unbundle their generation and transmission services, but not requiring corporate restructuring. However, the FERC also noted that if it were to become apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, the FERC would reevaluate its position and decide whether other mechanisms, such as ISOs, should be required.

In 1998, the FERC decided it was appropriate to begin this reevaluation, and initiated Docket No. PL98-5-000, *Inquiry Concerning the Commission's Policy on Independent System Operators*. The Commission filed comments with the FERC as a part of this inquiry, requesting that the FERC move forward with a more prescriptive policy regarding the formation of regional ISOs with regional transmission pricing mechanisms.

While the FERC's inquiry is still ongoing, and the ultimate outcome is still unclear, FERC Chairman Jim Hoecker recently publicly announced his intent to initiate and

[49] Order No. 888, 61 Fed. Reg. 21,540 (1996).

complete a generic proceeding that will vastly accelerate the establishment of ISOs (or similar entities) in every region of the country. Chairman Hoecker also called upon state regulators to help in this process, especially because demarcation between wholesale and retail is fast blurring, and state regulators have a stake in how the regional grid is operated and governed. The Commission will continue to be involved in this process and to work with the FERC as appropriate to help make ISOs a reality in the non-ERCOT regions of Texas, as well as the rest of the country.

2. The Las Cruces Case

The Commission has also become involved in another precedent-setting case at the FERC involving the City of Las Cruces, New Mexico (Las Cruces) and El Paso Electric Company (EPE).[50] In this case, Las Cruces, whose residents are currently bundled retail customers of EPE, is moving forward with the condemnation of EPE's electric distribution facilities in Las Cruces so that it can become a wholesale customer and purchase power at wholesale prices that are less than the regulated rates offered by EPE.

In Order No. 888, the FERC concluded that it was appropriate to allow a public utility to recover wholesale stranded costs caused by its customer's ability to access other wholesale suppliers as a direct result of the 1992 amendments to the Federal Power Act and subsequent new FERC rules.[51] The FERC rules state that wholesale stranded costs that occur when a "retail customer becomes a legitimate wholesale transmission customer of a public utility . . . through municipalization" are recoverable under the rule.[52]

In the FERC case, EPE argued that, under the provisions of Order No. 888, Las Cruces should be required to pay its fair share of stranded generation costs upon its departure from the EPE system, which it estimated to be approximately $100 million. In contrast, Las Cruces argued that it should not be required to compensate EPE for

[50] *City of Las Cruces, New Mexico*, Docket No. SC97-2-000 (pending).

[51] 18 C.F.R. § 35.26 (1997).

[52] 18 C.F.R. § 35.26(c)(1)(vii) (1997).

any stranded costs. The FERC Trial Staff estimated the stranded cost amount at approximately $30 million. Following a hearing, the administrative law judge (ALJ) issued an initial decision adopting the position of the FERC Trial Staff, which would provide EPE with approximately 30 percent of the stranded costs that it had claimed.

The Commission intervened in the proceeding out of concern that EPE's financial integrity may become unduly jeopardized, potentially affecting the quality of service for EPE's remaining customers—many of whom are located in Texas. In its briefs filed in the case, the Commission supported many (but not all) of the positions taken by EPE in the case as being reasonable and consistent with the policies and procedures adopted by the FERC in Order No. 888. In regard to the ALJ's initial decision, the Commission argued that it "does not permit [EPE] to recover a fair share of the costs that are stranded by the loss of [Las Cruces] as a retail customer. The [initial decision] would shift costs to EPE's other customers or shareholders, a result that is inconsistent with the [FERC's] intention in adopting a stranded cost recovery provision in the open access transmission rules."[53] A final decision by the FERC in this case is pending.

I. COMPETITIVE ISSUES IN RULEMAKINGS

The Commission initiated Project 17549,[54] *Code of Conduct for Electric Utilities and Their Affiliates*, in June 1997. In Project No. 14400, the Commission's rulemaking to address integrated resource planning (completed in 1996), the Commission had indicated that it would address at a later date the issues of energy services and cost unbundling and utilities' relationships with their affiliates. Project No. 17549 was established to address such affiliate activities, while energy services and cost unbundling would be addressed in a separate rulemakings, Project Nos. 19205 and 16536, respectively. The Commission also concluded a rulemaking in October 1998 regarding the offering of renewable energy tariffs by electric utilities.

[53] Public Utility Commission of Texas' Brief on Exceptions, Docket No. SC97-2-000 (July 30, 1998).

[54] Originally conceived as a set of rules to address affiliate activities in both industries, electric and telecommunications, the telecommunications portion of the project was later severed into a separate rulemaking, Project No. 18811, in February 1998.

1. Electric Affiliate Transactions

The need for more concrete affiliate rules was based on concern that a utility may favor its affiliates where those affiliates are providing services in competition with other, non-affiliated entities. In an increasingly competitive electric market, there exists a clear financial incentive for regulated utilities or their holding companies to subsidize their competitive activities with revenues or intangible benefits derived from their regulated monopoly businesses. It is the Commission's position that such activities are not in the public interest.

Further, current regulations governing the relations between and among units/divisions of an electric utility (or an electric utility holding company) may not be adequate to prevent or discourage anticompetitive behavior. The Commission intended, through this rulemaking, to articulate new rules that reflect the current state of competition in the electric power industry to provide regulatory certainty, facilitate more efficient competition to the benefit of customers, and fairly balance the equities among competing service providers. In developing these rules relating to affiliate activities, therefore, the Commission had three overall objectives: fostering fair competition for all participants in the market place, preventing cross-subsidization of competitive activities by monopoly rate payers, and preventing anticompetitive behavior and utilities' circumvention of their regulatory obligations.

The Commission Staff conducted several public workshops and informal discussions with interested parties in late 1997 and early 1998, and the Commission approved publication of the proposed rules early in the Summer of 1998. However, at its open meeting on August 12, 1998, the Commission decided to withdraw from consideration the rules proposed under Project 17549. The Commissioners indicated that this rulemaking was a lower priority project as compared to several other rulemakings that needed to be completed by the end of 1998, and that they anticipated resuming work on the Code of Conduct in the summer of 1999. The Commission further recognized the possibility that the Legislature would provide some specific direction on affiliate issues in the 1999 legislative session. Staff was directed to make some revisions to the proposed rules and then distribute copies of the revised discussion draft, which would be the starting point for future debate on the rules.[55] Based upon several recent affiliate transactions with the potential for anticompetitive effects, the Commission is reevaluating the adoption of this rule.

2. Utility Cost Separation

The implementation of non-discriminatory transmission pricing logically required the Commission to establish clear distinctions between transmission service and its upstream and downstream services, generation and distribution. Ultimately, the Commission concluded that additional segregation of distribution costs would be beneficial as part of its traditional ratemaking duties, and is a proactive approach that will provide additional benefits in the event of legislative action authorizing retail competition.

The new rules are necessary to allow the Commission to monitor more closely the activities conducted and the costs incurred in local delivery of electricity and in the provision of electric services to retail customers. The cost separation regulations require electric utilities to record and account separately for costs incurred in providing generation service, transmission service, distribution service, and customer service, based on the FERC system of accounts and regulations specific to the Texas Commission. The cost accounting and cost separation principles reflected in these rules are necessary to ensure that the costs associated with competitive services are not being subsidized by customers of regulated services and products. Cost tracking of certain activities by sub-account may become necessary to allow the Commission to identify the cost of specific activities.

The Commission recognizes that these rules promote three related goals: (1) separating the costs of electric service by function so that the commission can monitor the cost of service components; (2) initiating the process of removing regulation from those services and markets that are sufficiently competitive so that

[55] The revised discussion draft is available on the Commission's Internet site at http://www.puc.state.tx.us/rulemake/17549REV.htm.

regulatory-based pricing and oversight are no longer needed; and (3) enhancing public awareness of electricity production and delivery costs.

Ultimately, the Commission decided to concentrate on the first goal—cost separation—in this project. The Commission will address the second goal—removing competitive services from regulation—in a separate rulemaking proceeding relating to the unbundling of energy services (Project No. 19205) and in other rulemaking projects. The Commission has decided to examine the results of the cost separation rules and any statutory changes made during the 1999 legislative session before taking any further action.

The Commission required all electric utilities, except municipals, to comply with the cost separation rule including the requirement to file a cost separation implementation plan. The Commission allowed an additional twelve months for cooperatives and river authorities to implement new cost accounting requirements as compared to the investor-owned utilities. This extra time permits the Commission staff and the investor-owned utilities to complete the first iteration of implementation and compliance activities associated with the new regulations to facilitate the development and implementation for cooperatives and river authorities.

The Commission decided that the customer service reporting requirements relating to meters and the services provided to retail customers applied only to the investor-owned electric utilities and other electric utilities with more than 20,000 meters in service. The Commission adopted this threshold because small utilities tend to offer fewer special services. Therefore, the cost of complying with these reporting requirements is disproportionately higher for them than for larger utilities. The exemption applies to approximately 55 cooperative utilities.

3. Energy Services Unbundling

The Commission determined in its consideration of integrated resource planning rules in 1996 that anti-competitive practices may occur as a utility maintains or expands its presence in the energy-services sector. As a consequence, the Commission adopted regulations that require solicitations (competitive bidding) for demand-side resources.

Electric utilities must allow suppliers to bid for demand-side programs, and the bid must be selected from among all competing bids. This requirement brings integrity to demand-side resource acquisition, paralleling the process for bidding for power resources. Greater competition in the provision of demand-side resources is compatible with the goal of supporting the development of wholesale competition.

The Commission also determined that the unbundling of distribution functions would facilitate competition in existing retail energy-service markets. The Commission concluded that there is no longer a reason to maintain strict regulatory control over those markets. The provision of energy efficiency, for example, can be opened to greater competition, particularly if electric utilities offer accurate pricing signals to customers, acquire demand-side resources competitively, and allow the providers of energy services to obtain non-proprietary customer information maintained by the utility.

The Commission adopted cost separation regulations in August 1998, along with definitions for the terms "distribution service" (the wires) and "customer service" (all other regulated retail services). In the next step in unbundling, the Commission has proposed new regulations that define "energy service" and that require each electric utility to identify energy services offered by the utility. The purpose of the proposed regulations is to facilitate Commission review of energy-service offerings to permit a future determination of which energy services are monopoly services, and which are more appropriately provided by non-utilities. "Energy service," as used here, includes a broad set of activities that the ultimate consumer of energy would find useful. In addition to the bundled, regulated electric services, utilities offer optional energy services including appliance sale and warranty, electrical contracting and construction, energy audits, technical consultation and engineering services, project financing, power quality services, energy-related risk management, security lighting, and propane services, to name but a few. These are services that are available on a competitive basis, but that may be restricted by regulatory or utility practice. In addition to energy-service reporting, the Commission proposes that electric utilities file a plan to allow access to non-proprietary customer information. The information access plan would be reviewed and approved by the commission.

The Commission's proposed new rules are intended to facilitate future decisions regarding the regulation of electric utility activities as the utilities enter new retail markets or maintain a presence in existing energy-service markets. Regulation is necessary because electric utilities have a unique relationship with their electricity customers, and electric utilities maintain information which is not available to competitors in energy service markets.

Competitive markets can suffer if the monopoly functions of electric utilities are not appropriately constrained through regulation. Because many of the activities at issue have not been closely regulated in the past, there is significant resistance to the establishment of new regulations. Utilities believe that energy services ought to be provided unfettered by electric utilities to avoid losing economies of scale and scope. However, the Commission is not aware of any analysis indicating how the alleged losses of economies of scale and scope compare to the increased regulatory costs and the loss of efficiency as existing competitive markets are impaired. The Commission believes that it is premature to prohibit utilities from offering a full range of energy services at this time, but it is the Commission's preference that energy service activities not be performed by a regulated utility, but instead be offered through an unregulated, competitive affiliate.

4. Renewable Energy Tariff

On October 22, 1998, the Commission approved for adoption P.U.C. SUBST. R. 25.251, Renewable Energy Tariff. This rule establishes standards for utility offerings of energy generated from renewable resources, at a price level that covers the cost of acquiring the renewable energy. In adopting this rule, the Commission's objective is to provide customers with the opportunity to purchase renewable resources, thereby (1) furthering the statutory mandate in PURA § 34.005 to promote the development of renewable energy technologies; (2) responding to recently conducted Deliberative Polls™ which indicate that a significant proportion of customers place a high value on environmental quality in their respective communities and are willing to pay a higher price for "clean" energy acquired from non-polluting renewable resources; and (3) increasing the relative use of renewable energy to supply electricity to customers in Texas. In addition, a priority in the Commission's FY1999 is to encourage development of renewable energy tariffs.

The rule allows electric utilities to voluntarily offer their customers the option to receive all or part of their energy needs from renewable energy resources. If the resources cost more than the utilities' existing generation mix, renewable customers would pay a monthly charge above their regular bill. Utilities that offer this option to customers are required, under the proposed rule, to make the tariff available to all customers. Additionally, utilities are required to develop educational materials to distribute to all customers, informing them of renewable resources as supply-side and demand-side options, the utility's generation mix, and generation emissions. Participating utilities are also required to provide their renewable energy tariff customers with information annually on the status of the program and use of program funds.

J. FOCUSING ON THE CUSTOMER: THE EMERGING ROLE OF THE PUC

As the electric and telecommunications industries become increasingly competitive, the responsibilities of the Commission are changing. As the 1996 Texas Performance Review (TPR) report "Light Years"[56] noted, utility regulatory agencies nationwide are recognizing their major role inevitably will shift from traditional regulation to customer outreach, education and protection. The PUC's Office of Customer Protection (OCP) was established in July 1997 with funds appropriated by the 75th Texas Legislature.

OCP's staff performs various customer-related functions. A call center handles phone inquiries and takes complaints on the toll-free customer hotline. Its investigation staff attempts to resolve customer complaints and works with utilities to ensure compliance

[56] Light Years: The Future Of The Public Utility Commission in Texas, A Report from the Texas Performance Review (Jan. 1997).

with commission rules. The information and education staff handles media inquiries and conducts customer education. Combining these functions into one division allows OCP to quickly identify problems and inform and educate customers of the opportunities as well as the problems surfacing in the competitive marketplace.

One test of whether competition is in the public interest depends on how the customers of utility services fare. If rates rise or if customers experience more frustration and wasted money from abusive practices in the marketplace, then the customer's interest has not been well served. The following is a summary of the major consumer protection issues the PUC has dealt with in the electric industry over the past two years and its plans for protecting customers into the next century.

1. Addressing Customer Concerns

The PUC has expanded and publicized its toll-free consumer information line. Six staff members handle incoming calls in English and Spanish. In fiscal year 1998, call volume increased almost five-fold over the levels experienced in 1997. Calls from Spanish-speaking customers account for 8.5 percent of those calls.

With more information about how the Commission can assist them, more customers are filing complaints with OCP about their utility problems. Complaint caseloads have more than doubled from their FY '97 levels. To help manage the caseload more efficiently, OCP doubled its investigative and enforcement staff to a total of nine, including a bilingual investigator. Investigations of consumer complaints have resulted in almost $500,000 in refunds to Texas customers, far exceeding the $150,000 projection for FY '98. Enforcement staff also visited recreational vehicle parks in the Rio Grande Valley to investigate complaints on electric submetering.

More than 75 percent of the complaint caseload involves telephone issues. Complaints about electric issues comprise almost 8 percent of total caseload. Complaints about non-jurisdictional utility services like water, gas and cable television make up the remaining 17 percent.

2. Informed Choice in the Information Age

In its first year of existence the Office of Customer Protection has made great strides in customer education. OCP has produced more than a dozen publications in both English and Spanish. OCP publications are also available on the customer information Web page located at ***www.puc.state.tx.us***. OCP has also produced its first consumer newsletter, the "Public Utility Connection." It is published quarterly and distributed to customers across the state. In a newsletter column titled "Wrong Numbers," the PUC identifies utilities with the highest PUC complaint records. A list of "Right Numbers" indicates those utilities that have provided customers with above-average service quality.

Other outreach efforts include staff and commissioner visits to various parts of the state. In FY 1998 OCP visited Waco, Amarillo, the Rio Grande Valley, Tyler, Abilene, Midland, Beaumont and Laredo. These trips have been successful because local media helped spread the message about the importance of customer awareness. OCP also coordinates the agency Speaker's Bureau and provides resources and information within the agency for most speaking purposes.

3. Provider education

OCP has the responsibility for educating both utility customers and utility providers. To reach providers, OCP produces a monthly "Utility Advisory." Each issue highlights issues that are important to utility providers. In the months to come, OCP will also be conducting three workshops for utility providers.

4. What Customers Demand—Electric Quality of Service

At the same time the PUC created its Office of Customer Protection, it initiated a study with the LBJ School of Public Affairs at the University of Texas at Austin, to learn what customers want and expect from their electric utility company. The 134-page report,[57] issued to the PUC in May 1998 after a series of customer focus groups, recommends that customers be compensated for poor service and that utilities be

[57] *What Customers Demand: Quality of Service in the Electric Utility Industry in Texas*, Lyndon B. Johnson School of Public Affairs, The University of Texas at Austin (1998).

penalized for poor service and rewarded for excellent service to customers. The report also suggests an annual utility report card and performance-based ratemaking to tie utility rates to standards set for customer satisfaction, service reliability and other criteria. The report issues the following recommendations for Commission consideration:

- annual "customer satisfaction surveys" by each utility
- additional utility service interruption reporting to the PUC
- revised electric utility bills
- better meter-reading information and equipment
- complaint follow-up procedures
- special needs hotline numbers
- e-mail addresses for customer service representatives
- a four-hour response on utility service calls
- "Call Before You Dig" telephone numbers available at all times
- disclosure statements for new accounts
- availability of all utility information in Spanish in areas where Spanish-speaking customers reside.

5. Utility disconnection moratorium

Concern over health problems during one of Texas' hottest summers prompted the PUC to adopt an emergency rule which prohibited regulated utilities from disconnecting residential customers for non-payment of utility bills from August 12 until September 30, 1998. The rule also required utilities to establish deferred payment plans up to six months for customers who needed help paying their electric bills. While the emergency rule did not apply to municipal utilities, many complied voluntarily with portions of the rule. The action was initiated by a request by Texas Legal Services Center and Texas Ratepayers Organization to Save Energy (Texas ROSE) in August 1998.

OCP, working closely with the Texas Department of Housing and Community Affairs (TDHCA), publicized the disconnection moratorium statewide with press releases, fact sheets and customer newsletters, and then warned customers to make payment arrangements or seek assistance before the rule expired.

6. Customer Friendly Rules

The 1997-98 Appropriations Act required for the first time that all state agencies review their rules for readoption, amendment or elimination by 2001. The Commission plans to beat the four-year deadline by two years, finishing its review by June 1999.

Every Substantive and Procedural rule, including those on customer service, is being scrutinized to see if the reasons for adopting it still exist. OCP is reviewing and rewriting customer service rules so that the language is clear and easily understood by the consumer.

K. New Competitive Pressures

1. Wholesale vs. Retail Transactions

Since the enactment of PURA95, the electric industry has gone through significant changes in the way that electricity is bought, sold, and generated for the wholesale market. PURA95, however, did not explicitly define the terms "wholesale" and "retail" or "wholesale customer" and "retail customer." The lack of clear definitions has led some parties, particularly large customers, marketers and merchant generators, to push for an expanded wholesale market through petitions to the Commission in individual cases, or requests for Commission rulemaking proceedings.

The primary contested case before the Commission involving the distinction between wholesale and retail electric service since the last legislative session addresses a petition filed by the Department of the Navy asking that three bases be considered wholesale customers, rather than retail customers of Central Power & Light Company

(CPL).[58] As a wholesale customer, a Navy station would resell electricity to others at the base in a retail (that is, end-use) transaction.

CPL, an electric utility serving portions of south Texas, has historically provided retail electric service to U.S. Navy bases in south Texas and along the Gulf coast. In the Navy case, the Navy argues that CPL is incorrectly billing it under retail electric service tariffs, rather than under wholesale tariffs. SOAH issued its Proposal for Decision (PFD) in this case on October 8, 1998. The SOAH ALJ recommends that the Navy should qualify as a wholesale purchaser of electric power. Based on this fundamental recommendation, the ALJ further recommends that the case proceed to a second phase of hearings (Phase II) to determine, among other things: how CPL is to be compensated for stranded investment attributable to the Navy; how stranded investment should be allocated to the Navy; whether each base must obtain a certificate of convenience and necessity; and how service reliability concerns be addressed.

The Commission considered the PFD at its December 14, 1998 open meeting, and agrees generally with the ALJ's recommendations. The Commission concludes that the Navy is a wholesale purchaser based on the Navy's extensive outdoor system for distributing and metering electricity to ultimate consumers. The Commission likened the Navy's distribution system to electrical distribution systems owned and operated by small electric cooperatives and municipalities, which are wholesale purchasers. The Commission did not adopt the ALJ's additional rationale suggesting that sales by the Navy to other federal agencies located on the bases are "sales." As recommended by the ALJ, the Commission directed that the case proceed to Phase II.

The Commission also considered a petition for rulemaking filed in Project No. 18856 that proposed certain new definitions involving wholesale and retail customers.[59] Specifically, the petitioner suggested definitions for the terms "wholesale customer,"

[58] *Petition of the United States Department of the Navy on Behalf of the Navy and the Air Force for Declaratory Ruling Declaring the Departments of the Navy and the Air Force Wholesale Customers for the Purpose of Purchase of Electricity*, Docket No. 17180 (filed Mar. 11, 1997) (pending).

[59] *Rulemaking to Define Wholesale Electric Status and to Address Related Stranded Cost Issue*, Project No. 18856.

"wholesale load," "sale of electricity at wholesale," "retail customer," and "retail sale of electricity." The Commission denied the petition, noting that the issues were being addressed in the pending Navy case (above) and in the ongoing Sunset Review of existing Commission definitions in Project No. 17709.[60]

2. Corpus Christi Power & Light Company and Beaumont Power & Light Company

In October 1998, Corpus Christi Power & Light Company (CCP&L) filed with the Commission an application for a certificate of convenience and necessity (CCN) to provide electric service in Nueces and San Patricio counties.[61] Beaumont Power & Light Company (BP&L) filed a virtually identical application in November 1998. The only substantive difference between the BP&L and CCP&L applications is the location proposed to be served--BP&L proposes to serve the environs of Beaumont, while CCP&L proposes to serve the environs of Corpus Christi. Because of the similarity in applications, the following discussion focuses on the CCP&L application; the legal and policy issues raised in both application are the same.

In its application, CCP&L states that it "wants to bring access to competitive generation to those areas of Nueces and San Patricio counties currently served solely by CPL [Central Power & Light Company]." CCP&L is not seeking to serve any areas for which a rural electric cooperative has a certificate. While CCP&L's application requests a CCN to serve only the environs of the City of Corpus Christi, it also intends to apply for an additional certificate to serve customers within Corpus Christi when, and if, a franchise can be obtained.

To deliver wholesale power to its end use customers, CCP&L does not plan to construct significant new facilities, but to rely primarily upon the existing distribution facilities of CPL. In its application, CCP&L states:

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[60] *Review of Agency Rules in Accordance with HB 1, Section 167, 75th Legislature, R.S. (Subst. R. 26.1, 26.2, 26.3, 26.4; 25.1, 25.2, 25.3, 25.4; Repeal of Subst. R. 23.1, 23.2, 23.4)*, Project No. 17709.

[61] *Application of Corpus Christi Power & Light Company for a Certificate of Convenience and Necessity in Nueces and San Patricio Counties, Texas*, Docket No. 19950 (filed Oct. 7, 1998) (pending).

> The business plan of CCP&L contemplates minimal construction of new facilities to serve load. CCP&L would build those facilities to serve new customers previously without electric service or expanded requirements of any existing CCP&L customer. For the most part, however, CCP&L will seek to work with CPL and other existing utilities either to purchase unbundled distribution and related support services or to participate in a joint construction program to meet service area needs.

The CCP&L CCN application is the first of its kind, and involves significant competitive issues. At this point, the application is pending before the Commission and SOAH, and the outcome is unknown. However, the following are the relevant statutory CCN requirements that CCP&L must meet for the Commission to approve its application:

Sec. 37.051. CERTIFICATE REQUIRED.

(a) An electric utility may not directly or indirectly provide service to the public under a franchise or permit unless the utility first obtains from the commission a certificate that states that the public convenience and necessity requires or will require the installation, operation, or extension of the service.

(b) Except as otherwise provided by this chapter, a retail electric utility may not furnish or make available retail electric utility service to an area in which retail electric utility service is being lawfully furnished by another retail electric utility unless the utility first obtains a certificate that includes the area in which the consuming facility is located.

Sec. 37.053. APPLICATION FOR CERTIFICATE.

(a) An electric utility that wants to obtain or amend a certificate must submit an application to the commission.

(b) The applicant shall file with the commission evidence the commission requires to show the applicant has received the consent, franchise, or permit required by the proper municipal or other public authority.

Sec. 37.056. GRANT OR DENIAL OF CERTIFICATE.

(a) The commission may approve an application and grant a certificate only if the commission finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public.

(b) The commission may:

    (1) grant the certificate as requested;

(2) grant the certificate for the construction of a portion of the requested system, facility, or extension or the partial exercise of the requested right or privilege; or

(3) refuse to grant the certificate.

(c) The commission shall grant each certificate on a nondiscriminatory basis after considering:

(1) the adequacy of existing service;

(2) the need for additional service;

(3) the effect of granting the certificate on the recipient of the certificate and any electric utility serving the proximate area; and

(4) other factors, such as:

(A) community values;

(B) recreational and park areas;

(C) historical and aesthetic values;

(D) environmental integrity; and

(E) the probable improvement of service or lowering of cost to consumers in the area if the certificate is granted.

III. Summary of State Restructuring Legislation and Federal Restructuring Initiatives

The 1997 Scope of Competition Report included an overview of restructuring efforts in other states and at the federal level. Since that time, significant developments have unfolded across the nation with respect to the restructuring of the electric industry. This section provides an updated perspective of the competitive activities taking place outside of Texas, including a summary of state restructuring legislation and federal restructuring initiatives.

A. Summary of State Restructuring Legislation

Throughout the nation, while almost all states have launched formal electric restructuring investigations with varying intensity, several states have already enacted legislation or adopted regulatory plans designed to restructure the electric power industry (*see* Figure 4). To date, thirteen states have enacted legislation concerning the implementation of retail electric restructuring within the state, including: Arizona, California, Connecticut, Illinois, Maine, Massachusetts, Montana, New Hampshire, Nevada, Oklahoma, Pennsylvania, Rhode Island, and Virginia.

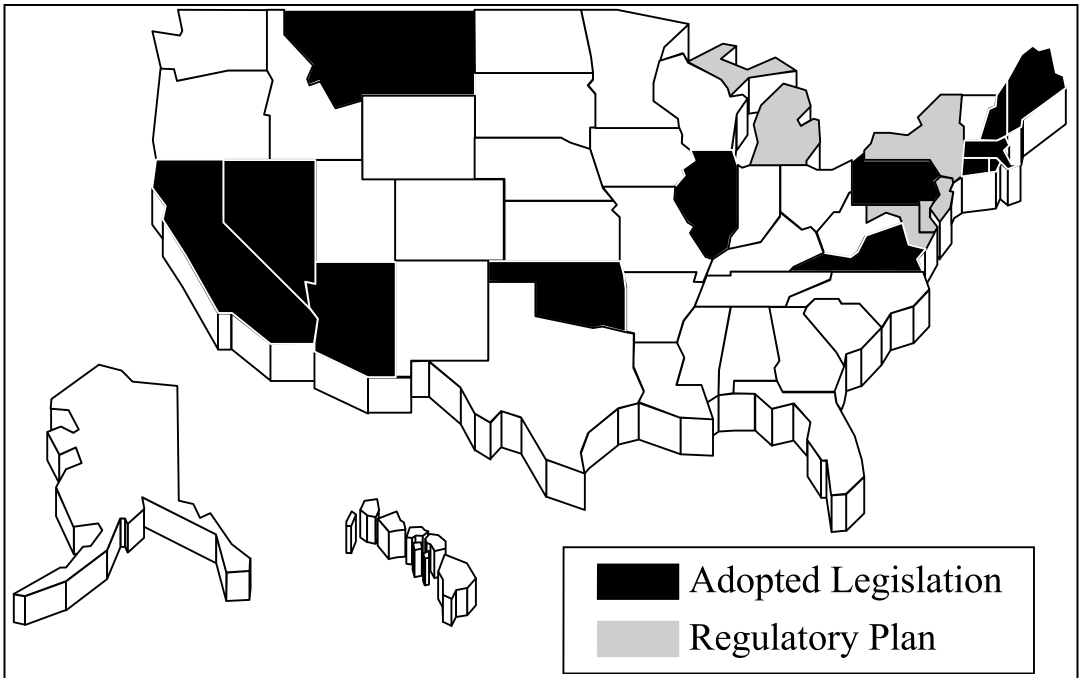

Figure 4 - Electric Restructuring Activity in the 50 States

The U.S. electric industry is currently changing from a vertically integrated, regulated monopoly to a restructured industry with its generation component and certain customer services (*e.g.,* metering and billing) becoming increasingly competitive. Events leading to changes in the industry include advances in power generation technology and trends toward competitive markets in other industries. Another very important factor propelling the industry toward change is the relatively large variation in regional electricity prices. The states that first began to address reform of the electric power industry (as early as 1994) are those states, primarily in the Northeast and California, that were experiencing prices significantly higher than other regions of the country. In addition, a few relatively low-cost states (Montana, Nevada, Virginia and Oklahoma) have also enacted legislation to restructure the electric industry in those states. Table 3 contains 1996 average residential rates, consumption and bills for the thirteen states with enacted restructuring legislation, with the same data for

Table 3 - 1996 Average Residential Rates, Consumption and Bills

STATE	Average Residential Rate (¢/kwh)	Rank *	Average Annual Residential Consumption (kWh)	Rank *	Average Annual Residential Bill ($)	Rank *
Texas	7.76	25	13,692	7	1,063	4
Arizona	8.95	15	11,586	20	1,036	7
California	11.33	8	6,434	47	729	37
Connecticut	12.05	5	8,164	37	984	10
Illinois	10.34	12	8,155	38	843	23
Maine	12.59	4	6,063	50	763	32
Massachusetts	11.27	10	6,704	45	755	34
Montana	6.22	43	10,315	27	642	44
Nevada	6.90	36	11,546	21	797	27
New Hampshire	13.44	3	6,275	44	904	18
Oklahoma	6.71	39	12,001	17	805	25
Pennsylvania	9.74	13	8,980	33	874	20
Rhode Island	11.81	7	6,146	49	726	38
Virginia	7.60	27	13,446	9	1,022	8
United States	8.36	n/a	10,275	n/a	859	n/a

* All rankings are in descending order from highest to lowest (1 = highest, 50 = lowest).

Texas and the U.S. average.[62] As indicated in Table 3, while Texas rates are average (25th highest), the total residential electric bill in Texas is among the highest in the nation (4th highest).

The list of issues associated with restructuring is not a short one. Appendix A contains a summary of the key issues for each of the thirteen states that have enacted retail electric restructuring legislation.[63] The following is a brief description of each of the issues contained in Appendix A.

- **Retail Access:** Currently, in regulated electric markets, end-users of electricity are constrained by law to purchase electricity from investor owned utilities, municipal utilities and electric cooperatives that are certificated to serve specific areas and customers. Retail access provides customers the opportunity to purchase

[62] *Statistical Yearbook of the Electric Utility Industry 1996*, Edison Electric Institute § 8, at 64 (1997).

[63] Appendix A was adopted without modification from *Comparison of Selected Electric Restructuring Legislation - Revised July 1998*, compiled by the Research Division of the Nevada Legislative Counsel Bureau. The Commission has not independently verified the accuracy of the information contained in the Nevada report.

electric services from the supplier of their choice. The states discussed in Appendix A have either initiated access or have adopted a date certain for its implementation. Some of these states have chosen to permit direct access for all customers at once, and some have opted to permit access in phases.

- **Pilot Programs:** These are experiments, limited in scope, designed to experiment with the workings of retail competition. The purpose of the programs is to provide customers, utilities and regulators with insights into the practical problems of retail competition.
- **Primary Responsibility for Implementation of Retail Competition:** Specifies the state agency or agencies responsible for the implementation of the policies embodied in the electric restructuring legislation in each state. To a varying degree in each state and for each issue, legislative policies range from a broad statement to detailed and proscriptive legislative language. In some states, regulatory agencies have been directed to develop restructuring plans, consistent with a legislative framework, to be submitted for legislative approval prior to implementation.
- **Independent System Operator (ISO):** Specifies the extent to which the creation of and/or participation in an independent transmission system operator arrangement is required under the state restructuring legislation. Participation in ISOs is often viewed as a critical component of competitive generation markets.
- **Power Pool:** Specifies the extent to which the state restructuring legislation requires participation in a mandatory power exchange in which all generators are dispatched in merit order on the basis of generation bid prices. The alternative to a mandatory regional power exchange is a bilateral market, in which buyers and sellers establish prices via individual contract or agreement. A voluntary power exchange can exist in a bilateral market structure.
- **Mandatory Rate Reductions or Rate Caps:** In many states, restructuring legislation has included mandatory rate reductions and/or the implementation of a rate cap for a specified period of time during the transition from a regulated to a competitive electric market (*see* Financing Rate Reductions and Stranded Costs).

- **Financing Rate Reductions and Stranded Costs:** Some states have implemented rate reductions through financing mechanisms (e.g., California). Additionally, once the magnitude of stranded costs is determined and the recovery level is specified, several options exist for the recovery of stranded costs. Securitization is one method of providing stranded cost recovery, whereby third-party debt is issued to finance the payment of utility stranded costs. Rate caps that use excess earnings to reduce stranded costs is another commonly used stranded cost recovery mechanism.
- **Treatment of Stranded Costs:** Stranded costs, or excess cost over market (ECOM), are defined as the historic fixed, sunk costs incurred by utilities in the regulated market to provide monopoly services that become competitive in a restructured industry, to the extent that these costs prove to be unrecoverable in a competitive market. For a variety of reasons, including advances in generation technology reducing the cost of producing electric power, these financial obligations may be unrecoverable in a competitive market because the market price is lower than the utility's cost-of service rate being recovered under regulation. Determining the magnitude of ECOM, whether utilities will be permitted to recover ECOM, and how they will be allowed to recover ECOM are critical elements of restructuring plans across the United States.
- **Divestiture of Generation:** Divestiture refers to an arm's-length transaction whereby ownership in utility-owned generation assets is transferred to an unaffiliated third party. Often, the term "divestiture" is also used to represent a transaction in which a utility's generation assets are transferred to an unregulated affiliated entity. However, a transfer of assets to an affiliate is more aptly termed "structural unbundling," and the use of the term "divestiture" should be reserved to refer to transactions in which asset ownership is transferred to an unaffiliated interest. Divestiture is used primarily as a tool to mitigate market power, which is caused by an excessive concentration of ownership in a regional supply market.
- **Reciprocity:** If retail access is permitted, a utility must permit access to its customers if it wishes to reach customers outside of its certificated service territory.

- **Customer Aggregation:** A process whereby an entity gathers together a group of customers and acts as their agent in the purchase of power.
- **Unbundling:** In the regulated electric market, electric customers receive a bill for services that is not itemized by function. That is, the customer is generally not aware of the separate prices for the various electric services represented in their bill—generation, transmission, and distribution. Unbundling, or breaking the current electric bill into its functional components, is a critical element in the implementation of retail competition if certain functions are to be subject to competition (generation and some customer services, such as metering and billing) while other functions are still regulated (transmission and distribution).
- **Customer Education/Customer Protection:** Deregulation will bring new companies into the utility industry and oversight activities will increasingly focus on customer service and protection. State commissions will increasingly focus on maintaining service quality and providing customers information and protection necessary to realize the benefits of competition.
- **Universal Service/Low Income Assistance Programs:** In a regulated environment, utilities can be ordered to provide universal service as well as low income assistance programs. In a deregulated environment there is no guarantee these programs will continue. Restructuring legislation may require the continued funding or expansion of these programs.
- **Renewable Energy, Conservation, and Environmental Issues:** Many states have enacted legislation with explicit policies and/or funding to promote renewable energy and/or conservation efforts in a restructured electric market. Additionally, actions have been taken in some states to ensure that the environment is not harmed by the introduction of competition in the electric markets.
- **Treatment of Transmission and Distribution:** Unlike the generation function, transmission and distribution (T&D) will continue to exhibit all the characteristics of a natural monopoly and will continue to be regulated in a restructured market. However, many states have redefined the role and responsibility of the T&D utility

and its relationship to competitive generation providers to accommodate a competitive market structure.

- **Legislative Oversight:** Indicates the degree to which legislatures have chosen to maintain implementation oversight over the electric restructuring process after the enactment of legislation.
- **Taxes:** The restructuring of the electric market and the introduction of competition may affect the level of various taxes collected and paid by utilities relative to the vertically integrated, regulated structure. Many states have addressed these issues directly in restructuring legislation.
- **Performance Based Ratemaking (PBR):** PBR is an alternative to traditional cost-of-service regulation of utilities, in which the utilities earnings are linked more to performance rather than simply a return on invested capital. In many states, PBR is being proposed as a reasonable substitute for cost-of-service regulation for those services that remain subject to regulation, i.e., transmission and distribution.

B. SUMMARY OF FEDERAL RESTRUCTURING INITIATIVES

In addition to the activities of individual states, electric restructuring is receiving increased attention in the U.S. Congress. As of July 1998, 19 electric restructuring-related bills have been introduced in the 105th Congress. These bills range from limited, single-issue legislation to comprehensive electric restructuring proposals. The Clinton Administration has also weighed in on the topic with S. 2287, a comprehensive restructuring bill sponsored by Senator Frank Murkowski (R-AK). Table 4 contains a summary of the sponsors and topics addressed in each proposed bill. A detailed summary of the key issues addressed in each of the bills introduced in the 105th Congress as of July 1998 is presented in Appendix B.[64]

[64] Appendix B was adopted without modification from *Comparison of Proposed Federal Electric Restructuring Legislation - Revised July 1998*, compiled by the Research Division of the Nevada Legislative Counsel Bureau. The Commission has not independently verified the accuracy of the information contained in the Nevada report. In addition, the following bills have been introduced since the date of compilation of Appendix B: H.R. 4432, introduced by Reps. Tom DeLay and Ed Markey, entitled "The Electric System Reliability Act of 1998"; H.R. 4715, introduced by Rep. Richard Burr, entitled "The Power Bill"; and H.R. 4798, introduced by Rep. Dennis Kucinich, entitled "The Electricity Consumer, Worker, and Environmental Protection Act of 1998."

Table 4 - Electric Restructuring-related Bills Introduced in the 105th Congress

Bill	Sponsor	Type of Bill
H.R. 338	Rep. Cliff Stearns (R-FL)	Limited (i.e., repeals Section 210 of PURPA).
H.R. 655	Rep. Dan Schaefer (R-CO)	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).
H.R. 1230	Rep. Tom DeLay (R-TX)	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
H.R. 1359	Rep. Pete DeFazio (D-OR)	Limited (i.e., addresses only conservation, efficiency, renewable energy, and universal service).
H.R. 1960	Rep. Ed Markey (D-MA)	Comprehensive (i.e., retail access, PUHCA and PURPA exemption).
H. R. 2909	Rep. Frank Pallone (D-NJ)	Limited (i.e., addresses environmental costs of generation)
H. R. 3927	Rep. Phil English (R-PA)	Limited (restricts the use of tax-exempt financing by governmentally owned utilities).
H. R. 3976	Rep. W. J. Tauzin (R-LA)	Limited. Repeals PUHCA.
H.R. 4183	Rep. Gerald Solomon (R-NY)	Limited (amends PURPA).
S. 237	Sen. Dale Bumpers (D-AR)	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
S. 1401	Sen. Dale Bumpers (D-AR) / Sen. Slade Gorton (R-WA)	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
S. 621	Sen. Alfonse D'Amato (R-NY)	Limited. Repeals PUHCA.
S. 687	Sen. Jim Jeffords (R-VT)	Limited (i.e., addresses only conservation, efficiency, renewable energy, and universal service). Repeals portions of Section 210 of PURPA.
S. 722	Sen. Craig Thomas (R-WY)	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).
S. 1276	Sen. Jeff Bingaman (D-NM)	Limited (i.e., does not mandate retail competition, but gives states authority to order it; requires FERC to establish and enforce national electric reliability standards).
S. 1483	Sen. Frank Murkowski (R-AK)	Limited (i.e., addresses only tax-exempt bond financing of public power entities).
S. 2182	Sen. Slade Gorton (R-WA)	Limited (addresses tax-exempt status of government-owned utilities).
S. 2187	Sen. Don Nickles (R-OK)	Limited (prohibits states from granting exclusive rights to sell electric energy).
S. 2287	Sen. Frank Murkowski (R-AK) [Introduced on behalf of the Clinton Administration.]	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).

IV. LEGISLATIVE RECOMMENDATIONS

For the reasons stated in the introduction, this report does not repeat the Commission's 1997 recommendations on implementing retail competition in the State of Texas. Rather, the report takes a look back at the competitive issues addressed by the

Commission over the last two years under the current market structure. However, as noted in the 1997 Scope of Competition Report:[65]

> *The nature and speed of changes in the electric industry . . . place the Commission in the situation of regulating in a rapidly changing environment without a great deal of Legislative direction on how to respond.*
>
> *Restructuring is already happening in the electric industry in Texas. Legislators and regulators are being pressed to decide whether, how, and when the electric industry should be restructured—but it should be recognized that with or without a formal policy direction or mandate, changes are already occurring in the industry that represent an evolution toward significant restructuring.*

These statements are still valid, and the need for policy directives is even more pressing now than two years ago. Several examples of these changes are discussed in this report, including selective discounted rate offerings by utilities; the commitment of one utility to voluntarily provide retail choice to its customers by the year 2003; new utilities seeking dual certification to compete in territories served by one utility; and several cases involving traditional retail customers seeking to become wholesale customers in order to access lower cost suppliers.

Change in the electric industry is also occurring at an increasing pace outside of Texas. Many states are moving forward with retail restructuring plans, and action by the U.S. Congress remains a possibility. Many current industry stakeholders as well as potential market participants believe that an eventual restructuring of the Texas electric industry is inevitable; however, substantial uncertainty exists regarding the timing and the details of the future market structure. This uncertainty is problematic in the regulated retail market as well as the competitive wholesale market, in that it is difficult for regulated utilities, customers, competitive wholesale providers and the Commission to plan prudently and make investments for the long term.

The combination of rapid change and uncertainty places increased pressure on Texas to reach decisions regarding if, how and when it will restructure its retail electric

[65] 1997 Scope of Competition Report, Volume I, at 49-50.

market. As it recommended in 1997, the Commission believes that a timely move to a competitive retail market that provides adequate protections for customers and the opportunity for all market participants to benefit is in the public interest. For that reason, the Commission asks for direction on this issue from the 76th Legislature.

Regardless of whether the 1999 legislative session results in the passage of retail restructuring legislation, the Commission recommends the following legislative changes that it believes are necessary to enhance wholesale competition in Texas over the next several years. Many of these recommendations may also be appropriate for inclusion as part of a retail restructuring package.

A. Transmission Issues

The authority of the Commission should be broadened and/or clarified in certain respects to further promote the development of competitive wholesale markets in the State, to ensure that the reliability of the transmission system is maintained or improved, and to encourage the development of new power generation projects that are required to meet its growing power needs of the State. Specifically, the Commission recommends the following changes:

1. Clarification of the Commission's authority to implement transmission cost recovery factors (subject to reconciliation) to facilitate the timely construction of required new transmission facilities or modifications to existing facilities.
2. Clarification of the Commission's authority to exempt certain minor facilities from the certificate of convenience and necessity requirement.
3. Formal statutory recognition of the ERCOT ISO and its role and responsibility, as set forth in the Commission's substantive rules, including recognition of the Commission's authority to supervise the operations of the ERCOT ISO as a forum of appeal, and clear enforcement powers to back up the ISO Director and Board.
4. Authority for the Commission to implement a unified control area in ERCOT under the operation and supervision of the ERCOT ISO, should the Commission find doing so to be in the public interest.
5. Authorize the Commission to require municipal utilities to submit annual transmission plans to the ISO for review.

6. Authority for the Commission to require a utility to join an ISO, if it finds that a viable ISO exists in the region where the utility provides service, and the utility's membership in the ISO would foster wholesale competition and would be consistent with the public interest.
7. Authority for the Commission to require a utility to seek FERC approval to offer transmission service under a regional transmission tariff, if it finds that a regional transmission tariff exists in the region where the utility provides service, the terms of the regional transmission tariff are reasonable, and the utility's offering of service under the regional transmission tariff would foster wholesale competition and would be consistent with the public interest.
8. Authorize the Commission to require non-regulated electric generators that are connected to the transmission system to file reports with the Commission and/or the regional ISO or reliability council in the area in which the utility provides service containing information necessary to ensure and maintain the reliability of the transmission system.

B. Integrated Resource Planning

In the rapidly changing electric industry, implementation of the current IRP statute has proved to be rather cumbersome and difficult to adapt, in many cases, to the dynamic marketplace. The Commission believes that clarification of certain policy goals and the provision of increased flexibility in implementation of the existing statute would serve to better promote the public interest. Specifically, the Commission recommends the following changes:

1. Provide more specific guidance to the Commission regarding the appropriate levels of low-income support programs and appropriate funding mechanisms.
2. Provide more specific guidance to the Commission regarding statewide policy goals relating to the development of renewable energy resources and energy-efficiency programs.
3. Provide the Commission with increased flexibility in the implementation of the integrated resource planning process, including the authority to waive specific statutory requirements, should the Commission find that doing so is consistent with the public interest.
4. To comply with PURA §§ 34.003 and 34.022, wholesale-only providers would need to issue an "all-source" solicitation where the most cost-effective supply-side or demand-side resource bid wins. However, the language in PURA §§ 34.003 and 34.022 conflicts with the ability of a wholesale-only provider to implement a DSM program. Thus,

clarification is requested regarding the apparent inconsistency between the language of PURA and the practical application of DSM to wholesale-only providers.

C. COMPETITIVE ISSUES

As noted in specific examples in this report, as the competitive wholesale market broadens in scope, the line separating wholesale and retail energy services becomes blurred. Likewise, as the number of competitive energy services available to customers continues to grow, the division between regulated and competitive energy services becomes increasingly difficult to monitor and regulate, giving rise to the potential for vertical market power abuses, such as cross-subsidization and self-dealing. Further, changes in electric markets are occurring in other states and at the federal level that require the Commission to become more involved and responsive to multi-jurisdictional concerns than in the past. The Commission believes that its authority should be broadened and/or clarified in certain respects to protect the public interest in this period of rapid market change. Specifically, the Commission recommends the following changes:

1. Clarify the Commission's authority to determine and assign stranded cost obligations, where appropriate, that stem from changes in the Public Utility Regulatory Act that were enacted in 1995 regarding the implementation of competition in the wholesale market. This authority should extend to situations of former retail customers turned to wholesale customers, as well as other post-1995 structural changes that could result in stranded costs or the shifting of costs among utility customers.
2. Strengthen the Commission's enforcement powers and the ability to assess administrative penalties for non-compliance with provisions of PURA or Commission rules. In particular, PURA § 15.024(c) prohibits the Commission from assessing an administrative penalty if the violation is remedied in 31 days and was accidental or inadvertent. In light of the requirement in PURA § 15.023(c)(5), which requires the Commission to consider efforts to correct the violation in its determination of the amount of the administrative penalty, if any, the Commission believes that the remedy period unreasonably limits the authority of the Commission to consider the assessment of administrative penalties that may be in the public interest.
3. Authorize the Commission to prohibit electric utilities from providing competitive services, as defined by the Commission, except through

structurally separate affiliates, including the adoption of affiliate rules and codes of conduct.

4. Clarify the Commission’s authority to require electric utilities to unbundle costs, rates, and services, as specified by the Commission and consistent with the public interest.
5. Clarify the Commission’s authority to adopt alternative forms of incentive-based regulation for electric utilities, such as performance-based ratemaking (PBR).
6. Authorize the Commission to work jointly with other state agencies to address environmental issues, establish accounting rules, cost allocation procedures and joint audit and affiliate abuse complaint procedures.
7. Authorize the Commission to coordinate with the regulatory bodies of other states and participate in any regional regulatory bodies that may be created to study or implement electric restructuring.
8. Authorize the Commission to establish rules for electric utilities that are responsive to changes in federal law.
9. Authorize the Commission to review all mergers and acquisitions by electric utilities that are not currently subject to Commission review, and provide the Commission with the authority to condition or prohibit the transaction if it finds that the merger will unduly restrict competition, enhance market power, or is otherwise not in the public interest.
10. Authorize implementation and funding for a Commission-sponsored customer education program to inform and involve customers in the rapidly changing electric market or, in the alternative, authorize the Commission to supervise such a program implemented by utilities.

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Start Date of Retail Competition	
Nevada **A.B. 366** **July 16, 1997**	Customers may begin obtaining generation, aggregation, and any other potentially competitive services from alternative seller no later than 12/31/99, unless PUC determines that different date is necessary to protect public interest. (Section 39, p. 12)
Arizona **H.B. 2663** **May 29, 1998**	Not later than 12/31/98. (p 15*) *Page numbers are from the Internet version of the bill.
California **H.B. 1890** **August 31, 1996**	1/1/98 (p. 30, 42)
Connecticut **Substitute H.B. 5005** **April 29, 1998**	7/1/00 (p. 9)
Illinois **H.B. 362** **December 16, 1997**	On or before 10/1/99, any nonresidential, retail customer whose average monthly demand exceeds 4 megawatts (mW) or any commercial retail customer doing business at 10 or more separate locations within a utility's service area and whose electrical usage exceeds 9.5 mW may choose an alternative supplier. A mandatory transition period exists from the effective date of the Act through 1/1/05. (p. 6, 12)
Maine **H-568** **(LD 1804)** **May 23, 1997**	Beginning on 3/1/00, all consumers have right to purchase generation services from competitive providers. (p. 1)
Massachusetts **H-5117** **November 25, 1997**	3/1/98 (p. 1, 54)
Montana **S.B. 390** **May 2, 1997**	On or before 7/1/98, customers with loads greater than 1000 kW must have opportunity to choose electric supplier. Co-ops may file notice with PSC, within one year after effective date of Act, electing not to participate in retail access. (p. 4, 11) * Page numbers are from the Internet version of the bill.
New Hampshire **H.B. 1392** **May 21, 1996**	PUC to implement in most expeditious manner and no later than 1/1/98. PUC may delay to 7/1/98 but not longer without legislative approval. (p. 9)
Oklahoma **S.B. 500** **April 25, 1997**	All retail customers are permitted to choose their retail electric energy suppliers by 7/1/02. (p. 3-4)
Pennsylvania **H.B. 1509** **November 26, 1996**	Transition period to begin on 1/1/97. All customers to have retail access by 1/1/01. (p. 39, 84)
Rhode Island **96-H 8124 Substitute B** **August 7, 1996**	By 1/1/97 each distribution company shall file with PUC plan for transferring ownership of generation, transmission, and distribution facilities into separate affiliates. Company shall implement plan within 3 months after retail access is available to 40 percent of kilowatt hour (kWh) sales in New England. PUC may extend time if necessary. (p. 17-18)
Virginia **H.B. 1172** **April 15, 1998**	1/1/04 * The bill is only one page so no page numbers are needed.
Phase-in of Retail Competition	
Nevada **A.B. 366**	PUC may establish different dates for different services and different geographic areas and authorize retail competition in gradual phases. Utilities shall submit to PUC plan for compliance with Act, including information PUC needs to: set rates (e.g., utilities' cost to provide service and estimate of required revenue), allocate costs of service among customers, and adopt regulations for potentially competitive services. PUC may exempt sellers from certain portions of Act if necessary to achieve effective competition. (Section 39, p. 12; Section 49, p. 20)
Arizona **H.B. 2663**	Not later than 12/31/98, at least 20 percent of the 1995 retail load, at least 15 percent of which shall be reserved for residential customers, shall be opened by public power entities (PPEs) to retail competition. PPEs shall open their entire service territory not later than 12/31/00. Beginning 12/31/98 through 12/31/00, billing and collection services, metering, and meter reading shall be provided on a

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	competitive basis for retail customers with loads of 1 mW and above that have competitive electric generation service. After 12/31/00, billing and collection services for competitive generation services shall be provided on a competitive basis for all retail customers. After 12/31/00, service territories established by a certificate of convenience and necessity shall be opened to generation competition for all retail customers for any electric supplier that obtains a certificate from the Arizona Corporations Commission (ACC) or any PPE. A city or town with a population of less than 75,000 persons that does not elect to sell generation service in the service territory of another electricity supplier is exempt from the provisions of this Act. (p. 13, 15-16, 36)
California **H.B. 1890**	Full retail access for all customers no later than 1/1/02; phase-in to be equitable to all classes as determined by PUC. (p. 5, 42, 91)
Connecticut **Substitute H.B. 5005**	On and after 1/1/00, up to 35 percent of peak load of each rate class of company may choose electric supplier, provided such customers are located in distressed municipalities. As of 7/1/00, all customers may choose electric supplier. (p. 9)
Illinois **H.B. 362**	On or before 10/1/99, any nonresidential, retail customer whose average monthly demand exceeds 4 megawatts (mW) or any commercial retail customer doing business at 10 or more separate locations within a utility's service area and whose electrical usage exceeds 9.5 mW may choose an alternative supplier. On or before 10/1/00, governmental customers whose average monthly maximum demand equals 9.5 mW may choose another supplier. On or before 12/31/00, all remaining nonresidential retail customers are eligible to select an alternative supplier. On or before 5/1/02, all residential retail customers are eligible for retail competition. An electric utility may petition the Illinois Commerce Commission (ICC) to declare a tariffed service to be competitive. The ICC shall declare a service to be competitive for some identifiable customer group or clearly defined geographical area within the utility service area if the service or a reasonable substitute is reasonably available at a comparable price from one or more providers other than the petitioning utility. A customer taking a tariffed service that is declared competitive shall be entitled to continue to take the service on a tariffed based from the utility for a period of 3 years following the date the service is declared competitive. An electric cooperative or a municipal system may elect to allow retail competition to its customers. (p. 12-13, 50-51, 94-95)
Maine **H-568** **(LD 1804)**	Beginning 3/1/02, electric billing and metering services are subject to competition. PUC may establish earlier date except in no case may date be prior to 3/1/00. (p. 3)
Massachusetts **H-5117**	
Montana **S.B. 390**	Transition period begins 7/1/98 for customers with loads greater than 1000 kW; all customers eligible by 7/1/02, unless PSC determines added time is needed because workable competition does not exist. However, full implementation may not be delayed beyond 7/1/04 for customers with loads greater than 1000 kW and not beyond 7/1/06 for all other customers. Participating co-ops must adopt transition plans on or before 7/1/01, and transition period may not extend beyond 7/1/02, although transition plan may be altered under certain circumstances. (p. 3-5, 9, 12-13)
New Hampshire **H.B. 1392**	On effective date of Act, PUC shall undertake generic proceeding to develop statewide industry restructuring plan in accordance with legislative principles in bill. Final order is due by 2/28/97. PUC shall require all utilities to submit compliance filings. No utility shall be required, however, to commence implementation until filings representing 70 percent of retail sales have been implemented. (p. 9-10)
Oklahoma **S.B. 500**	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop proposed industry restructuring framework under direction of legislative task force. Commission shall address appropriate steps to achieve orderly transition and may include, in addition to directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. The defined period for transition shall be established. (p. 4)
Pennsylvania **H.B. 1509**	As of 1/1/99, maximum of 33 percent of peak load in each customer class will have direct access; 66 percent by 1/1/00; 100 percent by 1/1/01. PUC may extend 1/1/99 implementation date for 6 months. PUC to conduct milestone reviews to ensure technically workable and equitable transition. (p. 35, 39-41)
Rhode Island **96-H 8124 Substitute B**	On 7/1/97, distribution companies required to offer retail access from nonregulated power producers to all new commercial and industrial customers with anticipated annual demand of 200 kW or more,

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	all existing manufacturing customers over 1500 kW, and all state accounts, not to exceed 10 percent of total kW sales. On 1/1/98 access to include all existing manufacturers over 200 kW and all towns in state, not to exceed 20 percent of total kW sales. Access for all customers within 3 months after access is available to 40 percent or more of kW sales in all New England states, but not later than 7/1/98. PUC may extend final deadline up to 6 months. (p. 24-25)
Virginia **H.B. 1172**	The transition to retail competition and deregulation of generation facilities shall commence on 1/1/02. Specifics of transition are to be defined by General Assembly (GA) and by regulation of State Corporation Commission.
Pilot Program	
Nevada **A.B. 366**	
Arizona **H.B. 2663**	
California **H.B. 1890**	
Connecticut **Substitute H.B. 5005**	
Illinois **H.B. 362**	During the mandatory transition period, a utility may at its discretion conduct one or more experiments for the provision or billing of services on a consolidated or aggregated basis or for the provision of real time pricing or other billing or pricing experiments and may include experimental programs offered to groups of retail customers possessing common attributes. The ICC shall review and annually report the progress, participation, and effects of such experiments to the General Assembly (GA). (p. 16-17)
Maine **H-568** **(LD 1804)**	
Massachusetts **H-5117**	The Department of Telecommunications and Energy (DTE) and Division of Energy Resources (DER) shall establish pilot program consisting of 4 initial aggregation programs, with 2 municipal programs and 2 county or regional government programs. (p. 153-154)
Montana **S.B. 390**	Beginning 7/1/98, utilities shall conduct pilot programs using samples of residential and small commercial customers. Utilities must file report with PSC and transition advisory committee on or before 7/1/00 analyzing results of pilot programs. Co-ops may also establish pilot programs for customers with loads less than 1000 kW. (p. 3-4, 9)
New Hampshire **H.B. 1392**	
Oklahoma **S.B. 500**	
Pennsylvania **H.B. 1509**	PUC has authority to require utilities to submit proposals for pilots to begin 4/1/97. Program must commit 5 percent of peak load for each customer class. Minimum period for pilot is 1 year and shall include evaluation process as directed by PUC. (p. 42-45)
Rhode Island **96-H 8124 Substitute B**	
Virginia **H.B. 1172**	
Primary Responsibility for Implementation of Retail Competition	
Nevada **A.B. 366**	PUC shall promulgate regulations to implement Act and shall determine which electric services are potentially competitive. Such services are defined as ones that: will not harm one or more customer classes; will decrease cost; increase quality or innovation, where effective competition is likely to develop; will advance competitive position of state; and won't jeopardize safety or reliability. If PUC determines that market for potentially competitive service does not include effective competition, it shall establish method for determining prices, terms, and conditions of service. Effective competition means individual seller can't significantly influence price of service. (Sections 39-52, p. 12-22; Section 337, p. 149)

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Arizona **H.B. 2663**	PPEs shall determine terms and conditions for competition in retail generation service consistent with the Act. PPEs and the ACC shall coordinate their efforts in the transition to competition in generation to promote consistent statewide application of their respective rules, procedures, and orders. In order to transition to competition for generation, the ACC's authority to implement specified steps in the transition to competition is confirmed. Among the ACC's powers that are confirmed is the authority to open the service territories of public service corporations (PSCs), establish reasonable requirements for certificating and regulating PSCs that are electric suppliers, controlling the service territories of PSCs to require electric distribution utilities to provide certain services such as billing and collection, metering and meter reading, and to act as a supplier of last resort. The ACC's authority to adopt rules protecting the public against deceptive and unfair practices and over certain affiliate transactions is also confirmed. The ACC is authorized to exempt totally or partially certain competitive services of PSCs from certain provisions of the Act. (p. 14, 31-32, 35-36)
California **H.B. 1890**	PUC. (p. 42)
Connecticut **Substitute H.B. 5005**	The Department of Public Utility Control (DPUC) shall examine and regulate transfer of existing assets and franchises, expansion of plant and equipment of existing companies, operations and internal workings of companies, and establishment of level and structure of rates in accordance with specified principles. DPUC in consultation with Consumer Counsel (CC) shall monitor competition as it exists and evolves, and commencing 1/1/02, and annually thereafter, shall report to General Assembly (GA). (p. 80, 98)
Illinois **H.B. 362**	"Delivery services" means services provided by a utility that are necessary in order for the transmission and distribution systems to function so that retail customers in the utility service area can receive electric power from alternative suppliers. The ICC shall establish charges, terms, and conditions for delivery services. Each utility shall submit to the ICC, no later than 3/1/99, a delivery services implementation plan for nonresidential customers and no later than 8/1/01, a plan for residential customers. The ICC shall approve or modify the plan. To the extent a utility provides electric power or delivery services to alternative retail electric suppliers and such services are not subject to FERC jurisdiction, and are not competitive services, they shall be provided through tariffs filed with the ICC. Within 90 days after the effective date of the Act, the ICC shall conduct rulemaking to establish standards of conduct for utilities. The rules shall address relationships between providers of any 2 services and shall prevent undue discrimination and promote efficient competition. The proposed rules shall not be published prior to 5/15/99. The ICC shall also have authority to investigate and adopt rules requiring functional separation between generation and delivery services to create efficient competition. After 1/1/03, the ICC shall also have authority to investigate the need for and adopt rules requiring functional separation between competitive and noncompetitive services. The ICC shall adopt rules and regulations no later than 180 days after the effective date of the Act governing the relationship between utilities and affiliates to ensure nondiscrimination in services provided to a utility's affiliate and any alternative supplier including without limitation, cost allocation, cross subsidization, and information sharing. (p. 9, 15-16, 19, 68, 71, 73)
Maine **H-568** **(LD 1804)**	PUC. PUC may impose by rule any additional requirements necessary to carry out purposes of Act, except PUC may not regulate rates of competitive providers. (p. 5)
Massachusetts **H-5117**	The DTE is directed to require electric companies to accommodate retail access. On or before 1/1/98, each electric company shall file detailed plan with DTE to allow for introduction of retail competition in generation supply. DTE shall review each plan and issue order accepting, modifying, or rejecting plan. Each plan shall offer retail access to all customers as of 3/1/98. As of that date, no electric company and no affiliate shall be allowed to use distribution system of another electric company or make sales, either directly or indirectly, to end-use customers in another company's service territory unless DTE has approved company's restructuring plan. Any municipal lighting plant is exempt from requirement to allow competitive choice of generation. However, if municipal lighting plant has not allowed retail access by March 1, 2003, governing body of each city shall conduct study, which may include referendum, relative to competitive choice. (p. 53-54, 59, 101-102)
Montana **S.B. 390**	All public utilities shall submit transition plan to PSC not later than 1 year before retail choice is offered. PSC shall develop procedural schedule for considering transition plans and issue final order within 9 months after plan is filed. On approval of plan, PSC shall enforce plan in its final order. PSC may extend transition period if workable competition does not exist. Workable competition exists if competition is sufficient to inhibit monopoly pricing or anti-competitive price leadership. (p. 5, 12-13)
New Hampshire	PUC authorized to order such charges and other service provisions and to take such other actions

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H.B. 1392	substantially consistent with legislative principles in bill that are necessary to implement restructuring. (p. 3, 11)
Oklahoma **S.B. 500**	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop proposed industry restructuring framework under direction of legislative task force. Commission shall address appropriate steps to achieve orderly transition and may include, in addition to directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. (p. 4)
Pennsylvania **H.B. 1509**	PUC. (p. 28-29)
Rhode Island **96-H 8124 Substitute B**	PUC and Division of Public Utilities and Carriers. (p. 2)
Virginia **H.B. 1172**	State Corporation Commission shall adopt regulations governing transition to retail competition and all other aspects of implementation of retail competition.
Independent System Operator (ISO)	
Nevada **A.B. 366**	
Arizona **H.B. 2663**	PPEs are required to participate in and support an ISO, an independent system administrator, or other efforts to coordinate scheduling of generation or transmission within the state or region. (p. 19)
California **H.B. 1890**	Control of transmission system given to ISO. Utilities cannot collect CTC unless they commit control of their transmission assets to ISO. ISO governed by Oversight Board selected by governor and legislature. (p. 30, 36-39, 87, 90)
Connecticut **Substitute H.B. 5005**	The DPUC shall consult with ISO on regular basis regarding compliance with Code of Conduct in areas including procedures for ensuring nondiscriminatory access to transmission and distribution facilities. ISO shall implement procedures for provision of backup power, to satisfaction of DPUC. In order to obtain license from DPUC, supplier must be registered with or certified by ISO and must own or purchase capacity and reserves specified by ISO. As condition of holding license, supplier must comply with system rules and standards and any other reliability guidelines of ISO. DPUC shall maintain regular communications with ISO to ensure adequate, safe, and reliable electric supply. (p. 7, 33-34, 41, 44-46)
Illinois **H.B. 362**	A utility shall allow aggregation of loads as long as the aggregation meets the criteria for delivery established by an ISO to which the utility belongs. The GA finds establishment of one or more ISOs are required to facilitate open and efficient markets for electricity. Each utility owning or controlling in-state transmission must submit an application to FERC for joining or establishing an ISO. The ISO shall independently manage and control transmission facilities, provide for nondiscriminatory access to the transmission system for buyers and sellers; direct transmission activities of control area operators; coordinate, plan, and order the installation of new transmission facilities; adopt inspection, maintenance, repair and replacement standards for transmission facilities; and implement procedures to assure adequate and reliable service standards no less stringent than those established by the North American Electric Reliability Council. The state shall work cooperatively with contiguous states and FERC to form one or more regional ISOs. The ISOs' governance must be fair and nondiscriminatory and independent of any one market participant or class of participants. Participants in the ISO shall make available all information required by the ISO. Those utilities that have not filed an application to form an ISO with FERC by 6/30/98, or who have not received approval from FERC by 3/31/99, shall be overseen by a 5-member oversight board. The board shall oversee the creation of an ISO and determine the composition, initial terms of service, and appoint the initial members of the ISO board of directors. The oversight board shall consist of 3 persons appointed by the governor, 1 by the Speaker of the House, and one by the President of the Senate. The ICC shall require each utility not participating in a FERC-sanctioned ISO to petition FERC for permission to transfer functional control of transmission facilities to the Illinois ISO. Upon approval by FERC, the utilities may also elect to transfer ownership of their transmission facilities to the ISO. A sale, assignment, or lease of transmission facilities to an ISO is not subject to ICC approval under certain conditions. Utilities belonging to the Illinois ISO may withdraw upon joining another ISO approved by FERC. If a spot market, exchange market or other market-based mechanism providing transparent real time market prices has not developed, the ISO or a closely cooperating agent may provide an efficient competitive power exchange (PX) auction on a nondiscriminatory basis open to all suppliers. (p. 14, 38, 39, 81-85)
Maine	The governance of any ISO with responsibility for operations of regional transmission system must be

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H-568 (LD 1804)	fully independent of influence by market participants. PUC shall use all means within its authority and resources to advocate for and promote interests of Maine ratepayers in any FERC proceeding involving development, governance, operations, or conduct of ISO. PUC shall monitor events in region pertaining to development of ISO, management of competitive access to regional transmission system, and rights to negotiate potential contracts between buyers and sellers. If PUC determines that there is insufficient independence on part of ISO, PUC shall provide report to joint standing committee of legislature with recommendations to remedy problem. (p. 20, 22-23)
Massachusetts H-5117	The Division of Energy Resources is authorized to monitor any ISOs or PXs to determine extent to which they serve needs of retail customers and contribute to energy efficiency and fuel diversity goals. DTE is directed to coordinate with operator of bulk power system in New England, FERC, and other public utility commissions to adopt and implement appropriate policy initiatives and statutory reforms, including further development of bulk power system operator, to ensure independent operation of regional bulk power system in order to provide for full and fair competition while preserving reliability of system. Governor, through DTE, is directed to pursue formation of regional oversight committee to monitor any ISO serving New England/New York area. Committee shall encourage regional coordination of transmission oversight including execution of regional compact agreement in effort to jointly monitor issues of reliability and to require utilities to adhere to enforceable standards and protocols to protect reliability of regional transmission and distribution systems. (p. 18, 137-138)
Montana S.B. 390	
New Hampshire H.B. 1392	
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	All participants encouraged to coordinate plans and transactions through ISO or functional equivalent. ISO should, and PUC shall, set and enforce inspection, maintenance, and repair standards. (p. 23)
Rhode Island 96-H 8124 Substitute B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of ISO. (p. 22)
Virginia H.B. 1172	The commission and those parties involved in generation, transmission, and sale of electricity in Virginia shall work together to establish one or more ISOs by 1/1/01.
Power Pool	
Nevada A.B. 366	
Arizona H.B. 2663	
California H.B. 1890	Power Exchange established to operate efficient, competitive auction for electricity open to all suppliers on nondiscriminatory basis. (p. 5, 39)
Connecticut Substitute H.B. 5005	
Illinois H.B. 362	If a spot market, exchange market or other market-based mechanism providing transparent real time market prices has not developed, the ISO or a closely cooperating agent may provide an efficient competitive power exchange (PX) auction on a nondiscriminatory basis open to all suppliers. (p. 83)
Maine H-568 (LD 1804)	
Massachusetts H-5117	The DTE is authorized to monitor any ISOs or PXs to determine extent to which they serve needs of retail customers and contribute to energy efficiency and fuel diversity goals. (p. 18)
Montana S.B. 390	
New Hampshire	New England Power Pool should be reformed to compliment restructuring on regional basis. Any pool structure should not preclude bilateral contracts and should not preclude ancillary pool services from

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H.B. 1392	being obtained from non-pool sources. (p. 8)
Oklahoma **S.B. 500**	Legislative task force is authorized to retain consultants to study benefits of establishing Power Exchange which would operate as power pool allowing power producers to compete on common ground in state. (p. 9)
Pennsylvania **H.B. 1509**	PUC to take all necessary steps to encourage interstate power pools. PUC and utilities to work with federal and state governments, regional reliability councils, and interstate power pools to ensure reliable service. (p. 37)
Rhode Island **96-H 8124 Substitute B**	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of voluntary power exchange. PUC shall establish regulations for nonregulated power producers selling into state that are necessary to meet operating and reliability standards of regional power pool. (p. 22)
Virginia **H.B. 1172**	The commission and those parties involved in generation, transmission, and sale of electricity in Virginia shall work together to establish one or more regional power exchanges by 1/1/01.
Mandatory Rate Reductions or Rate Caps	
Nevada **A.B. 366**	Rates charged for residential services must not exceed those charged on 7/1/97. Rate cap remains in effect until 2 years after date PUC repeals regulations that established service pricing method. PUC may approve rate increase for residential service in amount not to exceed increase necessitated to ensure recovery by utility of just and reasonable costs. (Section 45, p. 18)
Arizona **H.B. 2663**	PPEs shall reduce the price for bundled service for retail customers who are unable to choose competitive generation by at least 10 percent over a maximum of a 10-year period. The 10-year period begins on any date between 1/1/91 and the effective date of the Act. Each PPE shall report its beginning effective date for the 10-year period and the proposed apportionment among its customer classes to the legislature by 12/31/98. (p. 19)
California **H.B. 1890**	Small customers receive at least 10 percent reduction on 1/1/98 and no less than 20 percent by 4/1/02. Can be financed with rate reduction bonds. (p. 5, 28, 49)
Connecticut **Substitute H.B. 5005**	From 7/1/98 til 12/31/99, base rates may not exceed rates in existence on 12/31/96. Rates may be adjusted by DPUC based on specified events. Not later than 10/1/99, DPUC shall establish standard offer for each distribution company, to be effective 1/1/00. Standard offer shall provide that total rate charged, including transmission and distribution, conservation and load management charge, renewable energy investment charge, generation, competitive transition assessment (CTA), and systems benefit charge, shall be at least 10 percent less than base rates in effect on 12/31/96. Not later than 10/1/02, each distribution company must report to DPUC information regarding customers receiving standard offer. Not later than 1/1/03, DPUC shall calculate for each customer class difference between average rate paid under standard offer and average rate paid by all other customers. Not later than 1/1/03, DPUC shall report, in consultation with CC, recommendations regarding whether to extend standard offer. At least annually, DPUC shall compute rate differential between residential and industrial customers. If differential has increased by 3 percentage points or more from rate differential that existed on 1/1/98, DPUC shall investigate. If differential is found to be due to anti-competitive activity, DPUC shall take appropriate enforcement action. If increase is found to be due to factors other than violation of law, DPUC shall take action to minimize differential to less than 3 percentage points. (p. 8, 40, 97-99)
Illinois **H.B. 362**	During the mandatory transition period, the ICC shall not authorize any increase or decrease in rates in effect on 10/1/96. Each utility serving more than 12,500 in-state customers must file tariffs effective 8/1/98 reducing each component of its base rates to residential retail customers by 15 percent from the rate in effect immediately prior to 1/1/98. If the utility serves more than 500,000 in-state customers, effective 5/1/02, it must reduce each component of its base rates to residential retail customers by an additional 5 percent from the rate in effect immediately prior to 1/1/98. However, if the utility's average residential retail rate is less than or equal to the average residential retail rate for a specified group of Midwest utilities, then it shall only be required to reduce base rates effective on 8/1/98 by 5 percent from the rates in effect immediately prior to 1/1/98 and then reduce its base rates effective 10/1/00 to residential retail customers by the lesser of 5 percent of the base rate immediately prior to 1/1/98 or the percentage by which the average rate exceeds the average rate of the specified Midwest utilities and reducing effective 10/1/00 each component of base rates for residential retail

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	customers by an additional 5 percent or the percent by which the average rates exceed the average rate for the specified Midwest utilities. Any utility reducing its rates by 15 percent on 8/1/98 shall include a statement in the bill for residential customers indicating that the rate reduction is a result of the Rate Relief Law of 1997 passed by the GA. (p. 28-31)
Maine **H-568** **(LD 1804)**	When retail access begins, PUC shall ensure that standard-offer service is available to all consumers of electricity. By 2/15/98, PUC shall provisionally adopt rules establishing terms and conditions for standard-offer service. If qualifying bids for standard-offer service in any service territory, when combined with regulated rates of transmission and distribution service and any stranded costs charge exceed, on average, total rate for electricity immediately before implementation of retail access, PUC shall investigate whether implementation of retail access remains in public interest or whether other mechanisms to achieve public interest and to adequately protect consumer interests need to be put in place. PUC shall notify legislature of results of its investigation and its determination. (p. 17-18)
Massachusetts **H-5117**	Transition to competitive market shall result in rate reductions of at least 10 percent, beginning on 3/1/98, as part of aggregate rate reduction totaling at least 15 percent upon subsequent approval of divestiture and securitization. Total rate reduction, net proceeds from divestiture, and net savings from securitization, in combination with rate reduction implemented by or on 3/1/98, shall be 15 percent on or before 9/1/99. As of 3/1/99, total average rates for all distribution company customers under standard service transition rate shall be subject to inflation cap through remainder of standard offer period. Rate reduction and inflation cap shall be subject to adjustment, review, and approval by DTE. Any distribution company shall provide electricity to agricultural or farming operations at rates, prices, and charges at least 10 percent below any other rate, with further rate, price, or charge considerations granted for off-peak consumption. (p. 4, 54, 59-60, 143-144)
Montana **S.B. 390**	Rate moratorium during transition period: 7/1/98 thru 6/30/00, utilities may not charge more than rates in effect on 7/1/98; 7/1/00 thru 6/30/02, utilities may not increase increment of rates normally allocated to electric supply-related costs above those associated with such costs in effect on 7/1/98. From 7/1/00, utilities may propose increases to rate increments normally allocated to T&D costs. Increased costs related to universal system benefit programs greater than those in effect on passage are exempt from rate caps, as are increased costs necessary to implement full customer choice including metering, billing, and technology. Certain other exemptions are allowed in extraordinary cases. (p. 6-8)
New Hampshire **H.B. 1392**	
Oklahoma **S.B. 500**	
Pennsylvania **H.B. 1509**	Rates capped at 1/1/97 levels for 54 months or until stranded costs are recovered and all customers have retail access, whichever is shorter. Additionally, generation component of rates is capped for 9 years or until distribution utility has collected stranded costs and all customers have direct access, whichever is shorter. (p. 30-31)
Rhode Island **96-H 8124 Substitute B**	Within 3 months after retail access is available to 40 percent of kW sales in New England and extending through 2009, distribution companies must arrange power contracts for their customers who have not contracted for their own power supply such that average revenue per kWh received from customer shall equal price for 12-month period ending 9/30/96, with certain inflationary adjustments. No customer who chooses this standard offer and subsequently contracts with their own supplier shall be required to pay exit fee (p. 26)
Virginia **H.B. 1172**	
Financing Rate Reductions and Stranded Costs	
Nevada **A.B. 366**	
Arizona **H.B. 2663**	PPEs shall establish a temporary surcharge on electric distribution services to pay for all or a portion of the unmitigated stranded costs of generation, if any, that were incurred before 12/26/96 and that may not be recoverable in a competitive market. The temporary surcharge on distribution services shall not cause the rates for standard offer service to exceed rates that were in effect on 12/30/98. The surcharge shall not continue past 12/31/04. (p. 17-18)

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California **H.B. 1890**	Provides for rate reduction bonds to finance rate reductions and stranded ("transition") costs. (p. 5-6, 75-87)
Connecticut **Substitute H.B. 5005**	To extent recoverable, stranded costs shall be recovered through CTA. CTA is nonbypassable charge authorized by DPUC. Rate reduction bonds are authorized to finance stranded costs but may not be used to recover stranded costs associated with nuclear generation. DPUC shall identify and calculate stranded costs collectible through CTA, upon application by company. DPUC shall hold hearing for each company and determine time frame allowed for collection of stranded costs through CTA, collection to begin on 1/1/00. On or before 1/1/04, company may apply for recovery of stranded costs associated with nuclear generation assets through CTA. Company may apply to DPUC for financing order with respect to stranded costs. DPUC shall hold hearing to determine portion of stranded costs that may be included in such funding. CTA shall be determined in equitable manner and shall be payable by customers on equal basis on same payment terms and be eligible or subject to prepayment on equal basis. DPUC shall fix and revise CTA in amount sufficient to pay principal and interest and reasonable and necessary expenses of rate reduction bonds. CTA shall be charged until rate reduction bonds are paid in full, and stranded costs not funded with rate reduction bonds are fully recovered. Except as otherwise provided, financing orders and CTAs are irrevokable. DPUC has no authority to revalue or revise stranded costs or to amend or rescind financing order. State pledges and agrees with holders of rate reduction bonds that state will not limit or alter CTA and financing orders until obligations are fully met. However, financing orders and rate reduction bonds do not constitute debt or liability of state or any political subdivision and do not obligate state or its political subdivisions to levy any tax for their payment. Rate reduction bonds shall mature no later than 12/31/11. Any municipal electric utility created on or after 7/1/98, and any muni that expands its service territory after that date, shall collect CTA from new customers. Any cooperative organized on or after 7/1/98 shall collect CTA from its members at rate set by DPUC. DPUC shall design process for setting CTA for self-generation facilities to offset any loss in revenue from such facilities toward CTA assessment. Except as otherwise provided, fee shall apply to self-generation facilities that begin operation on or after 7/1/98. Exit fee does not apply to self-generation facilities serving less than 4 residential units or that is installed in conjunction with expansion of facility operating before 7/1/98. (p. 14-19, 22-28, 39, 93, 95)
Illinois **H.B. 362**	The transition charge is a charge in cents per kWh calculated for a customer or class for each year in which a utility is entitled to recover transition charges. A detailed formula for the calculation of the transition charge is set out, including a "mitigation factor" which is to be subtracted from transition cost recovery. A utility is entitled but not required to implement transition charges. If the utility implements such a charge, it must be implemented for all delivery service customers. Such charges shall be collected on each kWh delivered from the date the customer first takes delivery until 12/31/06, unless the utility petitions for and receives an extension to no later than 12/31/08. The ICC will determine the mitigation factors to be used during any additional period. A utility is entitled to collect transition charges from retail customers taking power from alternative retail suppliers and the customer is obligated to pay the charges on a lump-sum basis before taking service from the alternative supplier unless the utility and the customer otherwise agree. Detailed provisions for the determination of market value used in the calculation of the transition charges are established. "Instrument funding charge" is established. This charge is a nonbypassable charge expressed in cents per kWh authorized in a transitional funding order to be applied and invoiced to each retail customer or class of customers obligated to pay transition charges. The Act provides for the recognition of "intangible transition property" creating rights of a utility or assignee to a transitional funding order to impose and receive instrument funding charges and all related revenues, collections, payments, or proceeds thereof. The ICC is authorized to issue transitional funding orders creating and establishing intangible transition property. The expected maturity date and the final date on which a utility or assignee is entitled to charge and collect instrument funding charges shall be no later than 12/31/08. Neither the transitional funding order nor the intangible transition property shall be subject to reduction, postponement, impairment, or termination by any subsequent action of the ICC. The intangible transition property created under a transitional funding order and the authority of the grantee to impose and collect instrument funding charges shall continue beyond the final date set forth in the order, until such time as all instruments authorized in the order have been paid in full. The state pledges with the holders of transitional funding instruments that the state will not in any way limit, alter, impair, or reduce the value of the intangible transition property created. The issuance of transitional funding instruments shall not obligate the state or any political subdivision to levy or to pledge any form of taxation, and such instruments shall be payable solely from the intangible transition property. The ICC is prohibited from issuing any transitional funding order prior to 1/1/98, and no utility shall issue any transitional funding instrument prior to 3/1/98 or after 12/31/04. (p, 8-11, 20-23, 36, 42-48, 87, 98-127)
Maine **H-568**	

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(LD 1804)	
Massachusetts **H-5117**	Financial mechanisms should be available to securitize portion of transition costs that cannot be divested. DTE may allow distribution company, upon commencement of mitigation efforts, to collect charge for net, nonmitigatable past investment commitments incurred prior to 1/1/96. Company that fails to commence and complete divestiture of non-nuclear generation shall not be eligible for securitization and rate reduction bonds. Company that chooses not to divest all non-nuclear generation shall submit nuclear and non-nuclear generation facilities and purchase power contracts to valuation by DTE. DTE shall require reconciliation of projected transition costs to actual transition costs by 3/1/00 and for every 18 months thereafter through 3/1/08. Securitization shall not be available until company has fully mitigated transition costs. All savings derived from securitization shall inure to benefit of ratepayers. DTE shall impose cap upon transition charge and in no instance shall that charge be adjusted for inflation. Effective 3/1/98, if utility and DTE have received at least 6-months' notice of customer's plan to install co-generation, renewable technologies, or to purchase electricity from such sources, customer shall not be subject to exit charge if customer meets certain specified conditions. The DTE may issue financing orders. Company may, by 1/1/99, file with DTE application that provides that its transition costs may be recovered through reimbursable transition costs amounts. Application shall specify that customers would benefit from reduced rates through issuance of rate reduction bonds. Except as otherwise provided, financing orders are irrevocable and do not constitute debt or liability of state or any political subdivision. Such rate reduction bonds shall be used to pay for mitigated transition costs. Repayment of bonds shall not extend for more than 15 years, unless otherwise approved by DTE. Any municipality exercising option to convert its street lighting service shall be required to compensate electric company for its unamortized investment. (p. 3, 7, 53-54, 56, 59, 75-77, 80-99)
Montana **S.B. 390**	PSC may authorize imposition and collection of fixed transition amounts and issuance of transition bonds. After 7/1/97, utility may apply to PSC for determination that certain transition costs may be recovered through issuance of transition bonds. If such bonds are not issued within 4 years of PSC order, order must terminate. Utility may apply for extension or renewal of order. Order must set forth term over which transition bonds are to be paid—not to exceed 20 years. Upon issuance of transition bonds, financing orders and fixed transition amounts must be irrevocable. Cost savings associated with and resulting from bonds must benefit customers. Proceeds from bonds must be used to recover, reimburse, finance or refinance transition costs, and to acquire transition property. Bonds may not constitute indebtedness or loan of credit against state or political subdivision thereof. Co-ops may fully recover transition costs approved by local governing body. (p. 2-3, 6-7, 10,16-21)
New Hampshire **H.B. 1392**	
Oklahoma **S.B. 500**	All transition costs shall be recovered by virtue of savings generated by increased efficiency in markets brought about by restructuring. All classes of consumers shall share in transition costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring. Study shall include but is not limited to examination of IOU financing and any other financial issues Commission deems appropriate. Final report shall be provided to legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania **H.B. 1509**	PUC may approve utility request for issuance of transition bonds for some or all of its stranded costs. If approved, utility's rates or its CTC must be reduced by amount equal to revenue requirement of stranded costs for which transition bonds have been issued. (p. 52-53, 69-84)
Rhode Island **96-H 8124 Substitute B**	
Virginia **H.B. 1172**	
Treatment of Stranded Costs	

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Nevada **A.B. 366**	When PUC determines electric utility providing noncompetitive service cannot meet conditions to also provide potentially competitive service, utility has reasonable opportunity to recover previously incurred costs of those services it elects not to provide in future. PUC shall determine recoverable costs associated with assets and obligations documented in accounting records of vertically integrated electric utility that are properly allocable to particular potentially competitive service as of date alternative sellers begin providing such service in this state. Shareholders of utility must be fully compensated for all such costs determined by PUC. In determining recoverable costs, PUC shall take into account extent utility was legally required to incur cost; extent market value exceeds costs for assets and obligations; mitigation efforts; extent to which previous rates have already compensated shareholders for risk of non-recovery; tax effects; and, where utility had discretion to incur costs, its performance relative to similar utilities. PUC may impose nonbypassable mechanism for recovery and determine time period for recovery Such determinations and procedures must not discriminate against market participant. (Section 43, p. 16; Section 46, p. 18)
Arizona **H.B. 2663**	Unmitigated stranded costs may include employee severance costs necessitated by competition including unemployment compensation, training, and severance benefits. A PPE's stranded cost recovery shall be determined based on consideration of at least the following factors: the impact of stranded cost recovery on the effectiveness of competition, customers of a PPE who do not participate in the competitive market, a PPE's ability to meet debt obligations, the prices paid by consumers in a competitive market; the degree to which a PPE has mitigated stranded costs, some assets have value in excess of book value, the appropriate treatment of negative stranded costs; time period during which stranded costs may be recovered, ease of determining the amount of stranded costs; applicability of stranded costs to interruptible customers, amount of generation from renewable sources owned by the PPE, and allowances granted other electric suppliers in the state for stranded cost recovery. Unmitigated stranded costs shall be allocated among customer classes in a manner consistent with the specific PPE's current rate treatment of the stranded asset, in order to affect a recovery that is substantially the same proportion as recovery of similar costs from customers or customer classes under current rates. Any reduction in purchases resulting from self-generation, demand-side management, or other causes not attributable to retail competition shall not be used to calculate stranded costs. (p. 17-19)
California **H.B. 1890**	Fair opportunity to fully recover costs of PUC approved generation-related assets, including work force realignments and buyouts of certain existing power contracts. PUC to identify and determine costs and categories that may become uneconomic. Such costs are recoverable from all customers on nonbypassable basis. Calculation based on book cost net against market value. Departing customers pay severance fee; remaining customers pay competitive transition charge (CTC) based on customer usage. CTC ends for most costs on 12/31/01; employee related cost recovery extends to 12/31/06. "Firewall" protects customers in one class from absorbing CTC exemptions granted in other classes. If local publicly owned utility elects not to allow retail competition, it cannot recover stranded costs. (p. 5, 31, 45-53, 60, 89-90)
Connecticut **Substitute H.B. 5005**	Determination of stranded costs should be based on principles of fairness and reasonableness and workers adversely affected by restructuring should be protected. Any non-nuclear generation not divested by 1/1/00 is ineligible for stranded cost recovery. Company is ineligible to claim stranded costs unless non-nuclear generation is sold in public auction in commercially reasonable manner. All net proceeds realized from sale that exceed total book value of all assets sold shall be netted against stranded costs. If company does not receive bids, DPUC shall calculate stranded costs. Company that does not publicly auction its nuclear generation not later that 1/1/04 is ineligible for stranded costs recovery. DPUC shall determine minimum bid price for each nuclear generation asset. If final bid is less than book value, company shall be entitled to recover difference between bid price and book value as stranded costs. If final bid exceeds book value, net proceeds above book value shall be netted against stranded costs. If no bids are received, DPUC shall calculate stranded costs. On and after 1/1/00 and prior to date when nuclear generation assets are sold at public auction or transferred to affiliate, difference between return of and on capital costs allowed in rates for nuclear generation asset and income capitalization value established for asset for interim period shall be collected through CTA. Company seeking to claim stranded costs shall mitigate to fullest extent possible. Mitigation shall include commitments from purchasers that purchaser will offer employment to nonmanagerial employees at wages and overall compensation not lower than employees' lowest level during 6-month period prior to date contract to divest was entered into; good faith efforts to negotiate buyout, buydown, or renegotiation of independent power contracts and purchase power contracts and reasonable costs of consultants appointed to conduct auctions. Mitigation may also include reallocation of depreciation reserves to existing generation assets consistent with Generally Accepted Accounting Principles (GAAP); reduction of book assets by application of net proceeds of any sale of existing assets; maximization of market revenues from existing generation assets; efforts to maximize current and future operating efficiency; voluntary write-offs of above-market generation assets and retirement of uneconomical generation assets. Mitigation shall not include expenditures to restart nuclear facility. Mitigation efforts and associated costs are subject to approval by DPUC. DPUC shall calculate stranded costs as of 1/1/00. DPUC shall calculate stranded costs for generation assets to be difference between book value and market value of prudently and efficiently managed

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	non-nuclear generating facility of comparable size, age, and technical characteristics in competitive market. DPUC shall calculate stranded costs at least every 3 years. Cost shall be included in CTA. On or before 1/1/04, company may apply for recovery of portion of nuclear generation assets determined DPUC to be eligible for reimbursement through CTA. At least every 4 years after date DPUC issues initial finding of value of stranded costs for nondivested nuclear generation, it shall adjust stranded cost calculation and CTA assessment accordingly to true-up stranded cost recovery. (p. 8-9, 11-14, 16-20)
Illinois H.B. 362	The state has an interest in providing utilities a reasonable opportunity to obtain a return on investments on which they depended in undertaking those commitments in the first instance. It is in the state's interest to protect the interests of utility employees who might be economically displaced in a restructured industry. The state further has an obligation to ensure that employees operating in a restructured industry have requisite skills, knowledge, and competence to provide safe and reliable electric service. Therefore, alternative electric suppliers must demonstrate the competence of their employees. Demonstration shall include completion of an accredited or otherwise recognized apprentice program. Impacts on employees and their communities of any necessary reduction shall be mitigated to the extent practicable through voluntary severance, retraining, early retirement, outplacement, and related benefits. Before any such reduction, the utility shall present to the employees a reduction plan. In the event of a sale of facilities, the utility's contract with the purchaser shall require the purchaser to hire a sufficient number of nonsupervisory employees to operate and maintain the facility, and these employees must be hired at a wage rate not less than the one in effect at the time of the transfer. The employees must also receive substantially equivalent fringe benefits and terms and conditions of employment, which must continue for at least 30 months after the sale. (p. 3, 87-90)
Maine H-568 (LD 1804)	Stranded costs are defined as utility's legitimate, verifiable, and unmitigatable costs made unrecoverable as result of restructuring and determined by PUC. For each utility, PUC shall determine sum of following to extent they qualify as stranded costs: costs of utility's regulatory assets related to generation; difference between net plant investment associated with generation assets, and market value of generation assets; difference between future contract payments and market value of utility's purchased power contracts. When determining market value of generation assets and purchased power contracts, PUC shall rely to greatest extent possible on market information. PUC may not include any costs for obligations incurred on or after 4/1/95, except: regulatory assets created after 4/1/95 and prior to 3/1/00, for amortization of costs associated with restructuring QF contract; costs deferred pursuant to rate plans; energy conservation costs; obligations incurred after 4/1/95, and prior to 3/1/00, that are beyond control of utility; and obligations incurred after 4/1/95, to reduce potential stranded costs. Utility must pursue all reasonable means to reduce potential stranded costs and to receive highest possible value for assets and contracts. PUC shall consider utility's efforts to mitigate when determining amount of stranded costs. PUC shall provide utility reasonable opportunity to recover stranded costs through rates of transmission and distribution. Nothing in Act may be construed to give utility greater or lesser opportunity to recover stranded costs than existed prior to retail access. Before retail access begins, PUC shall estimate stranded costs of each utility. PUC shall use these estimates as basis for stranded costs charge to be charged by each transmission and distribution utility when retail access begins. In 2003, and every 3 years thereafter until utility is no longer recovering adjustable stranded costs, PUC shall correct any substantial inaccuracies in estimates and adjust charges to reflect correction. Any change will be prospective only and may not reconcile past estimates to reflect actual values. PUC shall set amount of recoverable, stranded costs after calculating net aggregate value of all divested assets that had proceeds exceeding book costs against aggregate value of all other stranded generation assets. Commission may not shift cost recovery among customer classes in manner inconsistent with existing law. PUC shall conduct separate adjudicatory proceedings to determine stranded costs for each utility. In same proceeding, PUC shall establish stranded cost charges for each utility. Customer who significantly reduces or eliminates consumption due to self-generation, conversion to alternative fuel or DSM, may not be assessed exit or entry fee in any form. Absent other just cause, layoff after 3/1/00 is deemed to be result of retail competition. Each utility must file plan with PUC prior to beginning of retail access providing transition services and benefits for eligible employees. Such benefits include programs to assist employees in maintaining fringe benefits, up to 2 years of retraining and out-placement services, full tuition for 2 years at University of Maine or comparable technical school at discretion of employee, 24 months of continued health care insurance, and severance pay equal to 2 weeks of base pay for each year of full-time employment. Plan may include provisions for early retirement benefits. PUC shall allocate reasonable accrual incremental cost of such benefits to ratepayers through charges collected by transmission and distribution utility. All charges must be transferred to system benefits administrator in transmission and distribution utility and used to provide benefits and services provided for in Act. (p. 13-15, 21-22)
Massachusetts H-5117	The transition to competition should provide investors reasonable opportunity to recover prudently incurred costs. Recovery shall occur only after all practicable measures to mitigate stranded investments. Charges should be collected over specific period of time on nonbypassable basis and in manner that does not result in increase in rates. It is preferable that possible reductions in workforce be accomplished through collective bargaining and voluntary severance, retraining, early retirement, outplacement, and related benefits. On or before 1/1/98, each electric company shall

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	file with DTE detailed plan for restructuring. DTE shall approve charges for transition costs and shall audit and reconcile difference between projected transition costs and actual costs by 3/1/00 and every 18 months thereafter. Each plan shall include estimate and detailed accounting of total transition costs eligible for recovery, company strategy to mitigate such costs, proposed charges for recovery of transition costs, and other specified items. All proceeds from divestiture and sale of generation facilities in inure to benefit of ratepayers shall be applied to reduce transition costs. If company chooses not to divest generation facilities, stranded costs shall be net of any market value in excess of book value. DTE shall identify and determine costs and categories of costs recoverable through nonbypassable transition charge. DTE shall conduct comprehensive audit of each distribution company and applicable electric company in order to assure substantial compliance with act. DTE shall complete comprehensive audit no later than 12/31/98. DTE shall develop guidelines to determine which transition costs may be recovered by transition charge and guidelines shall include only following: (1) unrecovered fixed costs determined by DTE to have been prudently incurred, which were being collected in DTE-approved rates on 1/1/97, and that become uneconomic as result of competition; (2) DTE-authorized recovery for nuclear entitlements by companies that have divested their non-nuclear generation; (3) unrecovered amount of reported book balances of existing generation-related regulatory assets; and (4) amount by which costs of existing contractual commitments for purchased power exceeds competitive market price. In addition to foregoing costs, distribution company may recover through transition charge certain costs incurred after 1/1/96 that include following: (1) costs associated with employee-related transition costs, i.e., severance, retraining, early retirement, outplacement, supplemental unemployment benefits, and related expenses for personnel; however, no recovery for transition costs associated with officers, senior supervisory employees, and professional employees performing predominantly regulatory functions will be allowed. Allowable costs shall be eligible for recovery only until 3/1/05; (2) any payments in lieu of taxes; (3) any costs to remove and decommission retired structures at fossil fuel fired generation facilities. Companies seeking to recover transition costs shall mitigate such costs through efforts including divestiture of non-nuclear generation facilities, good faith efforts to renegotiate, restructure, reaffirm, terminate, or dispose of existing contractual commitments for purchase power that exceed competitive market prices, netting against such above-market costs any below-market assets other than those associated with transmission and distribution, obtaining written commitments that purchasers of divested operations will offer employment to impacted employees at wages and overall compensation not lower than employees' prior levels for period of 6 months, and any other mitigation and analytical activities DTE determines to be reasonable. Employee of generation facility or electric company terminated after 7/1/97, as result of restructuring, shall receive re-employment assistance benefits and health insurance benefits. Such benefits shall be in addition to any benefits employee may receive from collective bargaining contract. Employer where such eligible employee has been terminated shall be billed amount equal to 100 percent of amount of re-employment assistance benefits and 100 percent of amount of health insurance benefits. (p. 3-4, 40-41)
Montana **S.B. 390**	PSC shall allow recovery of transition costs including unmitigatable costs of QFs such as reasonable buyout or buy down, unmitigatable costs of energy supply-related regulatory assets and deferred charges, unmitigatable transmission costs related to generation and other power purchase contracts, except recovery of those costs is limited to amount accruing during first 4 years after PSC approves transition plan. Value of generation-related assets must be reasonably demonstrable and considered on net basis. Methods for determining value include estimating future market values, independent third-party appraisal, and competitive bid sale. Transition charges must be imposed within transition cost recovery period approved by PSC on case-by-case basis. Certain transition costs may have varying transition cost recovery periods. (p. 3, 6-7, 10)
New Hampshire **H.B. 1392**	Defined as costs, liabilities, and investments utilities would reasonably expect to recover under existing regulatory scheme but which they will not recover in competitive market. Such costs limited to existing, PUC-approved renegotiated, or new PUC-mandated, commitments. It is legislative intent to give PUC appropriate tools and guidance to address stranded costs. PUC shall balance interests of ratepayers and utilities. Nothing is intended to provide greater recovery than present law provides. Utilities should recover net nonmitigatable costs of environmental mandates and federally mandated QF contracts. Costs should be on net basis, verifiable, exclusive of transmission and distribution assets, periodically trued up. Recovery should be by nondiscriminatory, appropriately structured charge, fair to all customer classes, limited in duration, consistent with promotion of competitive markets, applied only to customers within distribution utility's service territory. Entry and exit fees are not preferred mechanisms. PUC may establish interim recovery charge good for 2 years after compliance filing, to be netted against final recovery charges. Interim charge sets no precedent for amount of final recovery charge. (p. 4, 7-8, 10-11)
Oklahoma **S.B. 500**	A procedure shall be established for identifying and quantifying stranded costs and for allocating such costs. Mechanisms shall be proposed for recovery of appropriate amount of prudently incurred, unmitigatable, verifiable stranded costs. Each entity must propose recovery plan that establishes its unmitigatable, verifiable stranded costs and limited recovery period designed to recover costs expeditiously, provided that recovery period and amount of transition costs shall yield transition

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	charge that shall not cause total price, including transmission and distribution services, for any consumer to exceed cost per kWh paid on date of this Act during transition period. Transition charge shall be applied to all consumers including direct access consumers, shall not disadvantage one class or supplier over another, shall not impede competition, and shall be allocated over period of not less than 3 nor more than 7 years. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring, which shall include but not be limited to examination of stranded costs and their recovery, and final report shall be provided to legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania **H.B. 1509**	Fair opportunity to fully recover amount of stranded costs PUC determines to be just and reasonable. PUC determines level of each utility's stranded costs to be collected through nonbypassable CTC applied to all customers accessing transmission and distribution systems. PUC must adhere to specifically enumerated principles in determining amount. Calculation based on utility's known and measurable net generation-related cost determined on net present value basis over life of asset that may become uneconomic despite mitigation efforts. Includes prudently incurred costs of work force realignments and power contract buyouts and excludes any costs previously disallowed by PUC as imprudent. (p. 21-22, 24, 26-27, 35-36, 49-52)
Rhode Island **96-H 8124 Substitute B**	Utilities should have reasonable opportunity to recover prudently incurred transition costs. Distribution companies who purchase wholesale power under all-requirements contract are authorized to terminate contract and pay termination fee. Such payments are recoverable from all customers through nonbypassable transition charge. Charge may include costs of regulatory assets, nuclear obligations, buyout of above market power contracts, net unrecovered commitments, and capital costs of generating plants. Charge continues until liabilities are satisfied, with true up calculations. Recovery time for certain specified components is limited to period from 7/1/97 to 12/31/09. From 7/1/97 to 12/31/00, charge shall recover 2.8¢/kWh, thereafter in amount set by PUC. (p. 3, 20, 28-30)
Virginia **H.B. 1172**	Just and reasonable net stranded costs shall be recoverable. Appropriate consumer safeguards related to stranded costs and considering stranded benefits shall be implemented as determined by GA and, thereafter, by commission regulation.
Divestiture of Generation Assets	
Nevada **A.B. 366**	A vertically integrated electric utility shall not provide potentially competitive service except through affiliate. PUC shall establish limitations on ownership, operation, and control of assets of provider of electric service to prevent anticompetitive conduct and ensure development of effective competition. Such conditions and limitations may include limitations on ownership, operation, and control of transmission facilities and any generation necessary to reliable and economic operation of such transmission facilities. Affiliate may provide potentially competitive service if PUC finds there is arm's length transaction that will not adversely affect effective competition and risk of anticompetitive behavior, and regulatory expense to prevent such behavior, is minimal; PUC shall adopt procedure to process affiliate request to provide potentially competitive service and shall make any required findings no later than 6 months before authorizing retail competition. (Section 39, p. 12; Sections 41-43, p. 15-16)
Arizona **H.B. 2663**	
California **H.B. 1890**	Essential to separate monopoly transmission function from competitive generation operations by use of ISO. PUC must approve retention of generation assets in same corporation with distribution assets after market valuation. (p. 29, 61)
Connecticut **Substitute H.B. 5005**	Not later than 10/1/98, each company shall submit unbundling plan to DPUC to unbundle and separate , by 10/1/99, all company's assets. Any non-nuclear generation not divested by 1/1/00 shall be separated by transfer on functional basis to affiliate legally separate from company's transmission and distribution assets. Any nuclear generation not sold by 1/1/00 shall be separated by transfer on functional basis to legally separate affiliate. DPUC shall hold hearing and issue final order approving or modifying each company's unbundling plan, in time to accomplish unbundling by 10/1/99. Each company that elects to divest itself of non-nuclear generation shall, not later than 10/1/98, submit divestiture plan to DPUC along with necessary documentation to approve auction procedure. DPUC shall issue final order approving or modifying plan in time to allow divestiture to be accomplished by 1/1/00. DPUC in conjunction with CC shall appoint consultant to conduct auction. DPUC shall not approve sale unless certain specified conditions are met. Bidder must meet all qualifications established under federal law, bidder must agree to preserve existing labor agreements, and sale must result in net benefit to ratepayers. Not later that 1/1/04, each company shall either submit its nuclear generation to public auction or shall transfer remaining nuclear generation assets to affiliate at book value. DPUC shall not approve sale unless certain specifications are met. Sale price must equal or exceed minimum bid established by DPUC, and bidder must meet all qualifications noted above for non-nuclear generation. In order for municipal electric utility to be licensed as competitive provider, muni must unbundle and separate its generation assets by sale or transfer to unrelated

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	entity or by transfer on functional basis to one or more separate divisions that are structurally separate from muni's transmission and distribution assets. Any buyer or transferee must preserve existing labor agreements. (p. 9-13, 39)
Illinois **H.B. 362**	During the mandatory transition period, a utility may implement a reorganization, other than a merger of 2 or more public utilities, and sell, assign, lease, or otherwise transfer assets to an affiliated or unaffiliated entity without approval of the ICC. If the utility proposes to sell, assign, or lease generating plants that bring the amount of net dependable generating capacity transferred equal to or greater than 15 percent of its net dependable capacity on the effective date of the Act, or 1 or more generating plants with a total net dependable capacity of 1100 mW, or T&D facilities that either bring the amount of T&D facilities transferred to an amount equal to or greater than 15 percent of the utility's total depreciated original cost investment in such facilities or represent an investment of $25 million in terms of total depreciated original cost, the utility shall provide information on how the utility will meets its service obligations in a safe and reliable manner. The ICC may prohibit the proposed transaction if it finds either that the transaction will render the utility unable to provide its tariff services in a safe and reliable manner or that there is a strong likelihood the transaction will result in the utility being entitled to request an increase in its base rates during the mandatory transition period. A sale, assignment, or lease of transmission facilities to an ISO is not subject to ICC approval. Within 90 days of the effective date of the Act, the ICC shall open a rule making proceeding to establish standards of conduct for utilities. The rules shall address relations between providers of any 2 services to prevent undue discrimination and promote efficient competition. The proposed rules shall not be published prior to 5/15/99. The ICC shall have authority to investigate the need for and to adopt rules requiring functional separation between generation services and delivery services that are necessary to meet the objective of creating efficient competition. After 1/1/03, the ICC shall also have authority to investigate the need for and to adopt rules requiring functional separation between an electric utility's competitive and noncompetitive services. (p. 35-39, 70-71)
Maine **H-568** **(LD 1804)**	On or before 3/1/00, each investor-owned utility shall divest all generation assets and generation related business activities other than contracts with QFs or demand-side management providers, facilities located outside U.S., or generation assets PUC determines necessary for utility to perform its transmission and distribution obligations. No later than 1/1/99, each utility shall submit to PUC plan to accomplish divestiture. PUC shall review plans and, by 7/1/99, issue order approving or modifying plan. Utility may apply for extension beyond 3/1/00. PUC shall grant extension if extension would improve sale value of assets. If extension is granted, utility shall transfer generation assets to distinct corporate entity by 3/1/00. After 2/28/00, each utility shall sell rights to capacity and energy from all generation assets except those necessary to perform its transmission and distribution obligations. PUC shall adopt rules governing procedure for divestiture. PUC shall require distribution utility to divest affiliated competitive provider if utility or affiliate has knowingly violated provisions of Act and violation resulted in or had potential to result in substantial injury to retail consumers. If, after effective date of Act, 10 percent or more of stock of distribution utility is purchased by entity, purchasing entity and any affiliate may not sell or offer generation service to any retail customer and, if PUC determines that affiliated provider obtains unfair market advantage as result of such purchase, PUC shall order distribution utility to divest affiliate. If PUC orders distribution utility to divest affiliate, distribution utility may not have affiliated interest in competitive provider after divestiture. (p. 2, 7, 11-12)
Massachusetts **H-5117**	Consumers can best be served by functional separation of generation from transmission and distribution. If company chooses to divest itself of existing non-nuclear generation, company shall transfer or separate ownership of generation, transmission, and distribution facilities into independent affiliates of company or functionally separate such facilities within 30 days of federal approval. Transmission facilities, including all rights-of-way, property, fibre optic cable, and other tangible or intangible assets used directly or indirectly in transmission as of 12/31/96, or acquired thereafter, shall be transferred to transmission company at price that shall equal book value of facilities on company's accounts, net of depreciation as of date of transfer. Distribution facilities, including items listed above, shall be transferred to successor distribution company under same terms as noted for transfer of transmission facilities. Newly created distribution company shall be prohibited from selling electricity at retail except as otherwise provided and shall be prohibited from directly owning, operating, or controlling transmission facilities, generating facilities, or marketing affiliates. Requirement to divest generation facilities shall be deemed satisfied if company divests its non-nuclear generation by competitive auction or transferring to affiliate company at value to be determined to be reasonable and appropriate by DTE. All proceeds from such divestiture shall inure to benefit of ratepayers and shall be applied to reduction of company's transition costs. If company chooses not to sell its non-nuclear generation facilities, company's recovery of transition costs shall be net of any market value in excess of book value and it shall transfer all non-nuclear generation to affiliate at price determined by DTE. There shall exist strict separation between such generation affiliate, and distribution and transmission operations of electric company. Generation company formed pursuant to Section 193 shall be prohibited from acquiring new generation facilities as of 3/1/98. Any marketing company formed by electric company shall be affiliate and separate from any generation, transmission, or distribution affiliate. DTE shall promulgate standards of conduct to ensure separation of such affiliates. Standards shall be consistent with following provisions:

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	(1) distribution company shall not give affiliates preferences relating to products or services; (2) all products, services, discounts, rebates, and fee waivers shall be available to all customers and suppliers simultaneously on comparable basis; (3) all requests for products, services, or information shall be processed in same manner and within same period of time; (4) no product, service, or rate agreement shall be conditioned on provision of any other product or service of affiliate; (5) distribution company shall not share with affiliate market information acquired or developed in course of responding to requests for distribution service or any proprietary customer information without written authorization from customer; (6) a distribution company shall refrain from representing that any advantage accrues to customers in use of its services as result of that customer dealing with affiliate; (7) distribution company shall not engage in joint advertising with affiliate; (8) employees shall not be shared with and shall be physically separated from affiliate. A company that fails to commence and complete divestiture of its non-nuclear generation shall not be eligible for securitization provisions and issuance of electric rate reduction bonds. Company that chooses not to divest all non-nuclear generation shall subject its nuclear and non-nuclear generation facilities and purchase power contracts to valuation by DTE. (p. 2, 54-57, 61, 80, 83)
Montana **S.B. 390**	To extent utility is vertically integrated, it shall functionally separate electricity supply, retail transmission, and distribution. PSC may approve functional separation but may not order divestiture or prohibit it. Utilities shall prevent undue discrimination in favor of own power supply and prevent any form of self-dealing that could result in noncompetitive electricity prices. Utilities must grant customers and suppliers access to the utilities' retail transmission and distribution systems on a nondiscriminatory, comparable basis. Utilities may satisfy these provisions if they adopt code of conduct consistent with FERC-approved code of conduct. Similar provisions apply to co-ops. (p. 2, 5, 9)
New Hampshire **H.B. 1392**	Restructuring should require at least functional separation of generation from transmission and distribution services. However, distribution companies should not be entirely precluded from owning small-scale distributed generation resources. PUC authorized to require that distribution and power supply services be provided by separate affiliates. (p. 2, 4, 11)
Oklahoma **S.B. 500**	A primary goal of restructured electric industry is to encourage development of competition through separation of generation services from transmission and distribution services. Entities what own both transmission and distribution, as well as generation facilities, shall not be allowed to use any monopoly position in these services as barrier to competition. Generation services shall be functionally separated from transmission and distribution services. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring, which shall include but not be limited to examination of unbundling of generation, transmission and distribution services, and market power. (p. 2-4, 6)
Pennsylvania **H.B. 1509**	PUC may permit but cannot require utility to divest facilities or reorganize its corporate structure. (p. 33-34)
Rhode Island **96-H 8124 Substitute B**	By 1/1/97, distribution companies must file plan with PUC to transfer ownership of generation facilities to separate affiliates. Every wholesale power supplier receiving contract termination fees must subject its generating facilities to market valuation through lease, sale, spin-off or other method. At least 15 percent of such facilities must be disposed of through this process. If company is subject to higher requirement in another state's restructuring proceeding, same amount will apply in Rhode Island. Implementation methodology must be filed with PUC by 7/1/97. Employees of distribution company must function independently of affiliated nonregulated power company under detailed standards of conduct. (p. 17, 31-32, 35-38)
Virginia **H.B. 1172**	Deregulation of generation facilities, as defined and determined by GA and regulations of commission, shall commence on 1/1/02.
Reciprocity	
Nevada **A.B. 366**	PUC to issue quarterly report to legislature evaluating, among other issues, opportunities to cooperate, formally or informally, with other states or with Federal Government in implementation of competition. (Section 53, p. 23)
Arizona **H.B. 2663**	A city or town providing distribution service shall not sell generation service outside its service territory as constituted on 1/1/98, or as later amended by mutual agreement, unless the entity has agreed to allow other suppliers to compete within its service territory. A generation and transmission co-op is prohibited from supplying generation service in the territory of a member-owned, nonprofit co-op corporation unless the generation and transmission co-op has the consent of the nonprofit corporation. (p. 1, 11)
California **H.B. 1890**	For utility to sell to another utility's customers, it must allow access to its own customers. Out-of-state utilities must enter into compact to adhere to enforceable reliability protocols to be allowed to sell to California retail customers.

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	(p. 29, 90-91)
Connecticut Substitute H.B. 5005	No municipal utility shall use transmission or distribution system or facilities of electric distribution company for purpose of providing generation services to end-use customer outside its service area unless muni is authorized by DPUC. In order to be authorized, muni shall provide open and nondiscriminatory access to all distribution facilities it owns or operates to all electric suppliers and shall allow customers within its service area to choose electric suppliers. No municipal electric energy cooperative shall be allowed to be electric supplier or to request authorization to provide electric generation services to any end-use customers. (p. 38-39)
Illinois H.B. 362	An alternative supplier must obtain a certificate of authority from the ICC. As one condition of such approval, the supplier must provide reciprocal access to its own service territory to Illinois utilities in whose territory it proposes to supply electricity, (p. 54-57)
Maine H-568 (LD 1804)	
Massachusetts H-5117	The commonwealth should enter into compact with other New England states and New York state that provides incentives for public and investor-owned electric utilities located in such states to sell energy to retail customers in Massachusetts which adheres to enforceable standards and protocols and protects reliability of interconnected regional transmission and distribution systems. (p. 3)
Montana S.B. 390	All suppliers must be afforded open, fair, and nondiscriminatory access to customers and comparable opportunity to compete. Distribution service providers or affiliates may not use another distribution service provider's facilities unless first provider offers comparable, nondiscriminatory access to its distribution facilities. Co-ops that elect not to participate in retail access may not use utilities' distribution systems unless there is pre-existing contract. (p. 11, 14)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	Any municipal corporation may voluntarily become subject to provisions of Act through nonrevocable election. Any municipal corporation that elects not to participate shall be prohibited from extending retail electric distribution service beyond its corporate limits with exception that it may continue to offer retail distribution service from lines owned on Act's effective date. (p. 4, 9)
Pennsylvania H.B. 1509	No entity regulated by PUC may use transmission or distribution system of another PUC regulated entity to supply electricity to end-use customer unless first entity allows other entity to sell to its customers. (p. 38-39)
Rhode Island 96-H 8124 Substitute B	
Virginia H.B. 1172	
Customer Aggregation	
Nevada A.B. 366	Customers may begin obtaining aggregation services from alternative seller no later than 12/31/99, unless PUC determines that different date is necessary to protect public interest. (Section 29, p. 11; Section 39, p. 12)
Arizona H.B. 2663	PPEs shall allow the aggregation of loads by multiple customers. (p. 16)
California H.B. 1890	All customer classes are entitled to aggregation on voluntary basis. Can be done by private parties, or governmental entities. Public bodies acting as residential aggregators must offer to include everyone within jurisdiction. (p. 43)
Connecticut Substitute H.B. 5005	An aggregator is person or municipality that gathers electric customers for purpose of negotiating purchase of electric generation services from electric supplier, or, Connecticut Resources Recovery Authority if it aggregates customers for purpose of negotiating electric generation services, provided that person, municipality, or authority is not engaged in purchase or resale of electric generation services and provided further that customers contract for generation services directly with electric supplier. Aggregator may include electric cooperative. Aggregators are exempt from certain portions of act. Two or more municipalities may join together to aggregate sale of electric services to end-use customers located within boundaries of such munis or to aggregate purchase of generation services for municipal facilities, street lighting, board of education, and other publicly owned facilities within muni, provided that muni registers not less than annually with DPUC. Office of Policy and Management shall provide technical assistance to municipalities that want to aggregate. DPUC shall propose standards and procedures to facilitate aggregation of electric load and end-use customers

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	into buying groups. Not later than 9/1/98, DPUC shall commence investigation into aggregation. Investigation shall consider relationship of aggregation to education outreach program, specified billing formulation requirements, solicitation procedures established pursuant to act, right to change electric suppliers, and third-party verification requirements. Investigation shall also consider whether some licensing requirements should be moderated for aggregators and whether some licensing requirements should not be imposed on municipalities or political subdivisions that act as aggregators. Not later than 1/1/99, DPUC shall report its findings and legislative recommendations to GA. (p. 6, 36, 46-47, 88-89, 96)
Illinois **H.B. 362**	"Alternative retail electric supplier" includes aggregators. A utility shall allow the aggregation of loads that are eligible for delivery services as long as the aggregation meets the delivery criteria established by the regional reliability council to which the utility belongs or the ISO to which the utility belongs. The ICC may adopt rules and regulations governing the criteria for aggregation of loads utilizing delivery services. Utilities shall allow such aggregation for any voluntary grouping of customers, including without limitation those having a common agent with contractual authority to purchase on behalf of all customers in the grouping. The tariffs of each utility serving at least 1 million customers shall permit governmental customers acting through an intergovernmental agreement to aggregate their monthly kWh energy usage and monthly kW billing demand. (p. 4, 14, 81)
Maine **H-568** **(LD 1804)**	When retail access begins, consumers may aggregate in any manner they choose. If public entity serves as aggregator, it may not require consumers within its jurisdiction to purchase generation service from that entity. (p. 2-3)
Massachusetts **H-5117**	The Division of Energy Resources (DER) shall provide technical assistance to municipalities and governmental bodies seeking assistance during transition to competitive market, including voluntary aggregation of their citizens' demand for electricity. Aggregator is entity that groups together electricity for retail sale purposes, except for public entities, quasi-public entities or authorities, or subsidiary organizations thereof, established pursuant to laws of commonwealth. Any municipality or group of municipalities acting together is authorized to aggregate electrical load of interested electricity consumers within its boundaries, provided municipality shall not aggregate load if load is already served by existing municipal lighting plant. Towns and cities may initiate process to aggregate electrical load after approval by town or city council. Upon affirmative vote of such council, municipality may establish load aggregation in consultation with DER. Any municipal load aggregation shall provide for universal access, reliability, and equal treatment of all classes of customers. DTE shall not approve any plan for municipal aggregation if price for energy initially would exceed price of standard offer unless municipality can demonstrate that price under aggregation plan will be lower than standard offer in subsequent years or that excess price is due to purchase of renewable energy. Participation by retail customer in municipal or group aggregation program must be voluntary. Program must allow retail customer to opt out and choose any supplier retail customer wishes. Any number of persons may associate together as cooperative for purchase, acquisition, distribution, sale, resale, supply, and disposition of energy or energy-related services to wholesale or retail customers. Any nonprofit institution or agency, executive office, department, board, commission, bureau, division, or authority including executive, legislative, and judicial branches of state or any political subdivision thereof may, unless located within boundaries of community serviced by municipal light department, become member of program for purpose of group purchasing of electricity and other utility services. All private, nonprofit, or cooperative aggregators shall submit license application to DTE. (p. 15, 48, 64, 121-123, 126, 129)
Montana **S.B. 390**	Aggregators may be licensed by PSC to aggregate retail customer purchases. Aggregators take title to electric energy as intermediary for sale to retail customers. (p. 2)
New Hampshire **H.B. 1392**	
Oklahoma **S.B. 500**	
Pennsylvania **H.B. 1509**	Permits PUC licensing of aggregators, brokers and marketers as suppliers of electric energy, including municipal corporations selling outside their municipal limits, to serve all customer classes. (p. 24, 53-56)
Rhode Island **96-H 8124 Substitute B**	Authorizes purchasing cooperatives, consisting of any group of electricity consumers, for negotiating with power producers. Co-ops may not engage in resale of power. Consumers may withdraw from co-op by giving 30-days' notice to co-op and any nonregulated power supplier under contract to co-op. (p. 8-9, 46-47)
Virginia **H.B. 1172**	

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Unbundling	
Nevada **A.B. 366**	PUC to determine which electric services are potentially competitive using set of specified criteria. Retail customers will have direct access to such services. (Section 39, p. 12-13)
Arizona **H.B. 2663**	PPEs shall establish unbundled ancillary electric transmission and distribution (T&D) and other service, prices, terms, and conditions that are nondiscriminatory and that reflect the just and reasonable price of providing the service. (p. 17)
California **H.B. 1890**	Each electric corporation shall propose stranded cost recovery plan to PUC, which must provide identification and separation of individual rate components. Bills shall disclose each component of total charge. (p. 49, 62, 71)
Connecticut **Substitute H.B. 5005**	Not later than 8/1/98, DPUC shall hold hearing and issue final order that unbundles prices or rates for electric generation services for each electric company from all other charges. On and after 7/1/99, each electric company or electric distribution company shall provide all customers with bill that separates generation services component from other charges. DPUC shall adopt by regulation standard billing format that enables customers to compare pricing policies and charges among electric suppliers. On and after 1/1/00, each electric company or electric distribution company shall include, at minimum, following information in each customer's bill: total amount owed by customer, which shall be itemized to show generation charges, and any additional charges imposed by electric supplier, transmission and distribution charges, including all applicable taxes and system benefits charge, CTA, conservation and renewable energy charge, and renewable energy investment charge; any unpaid amounts from previous bills listed separately from current charges; rate and usage for current month and each of previous 12 months in bar graph or other visual form; payment due date; interest rate applicable to unpaid amount; toll-free telephone number to report power losses to distribution company; toll-free telephone number for DPUC for questions or complaints; toll-free number and address of electric supplier; statement about availability of information concerning electric suppliers. Energy Advisory Board in consultation with DPUC and CC shall conduct study of metering, billing, and collection services by electric distribution companies and consider whether customers would be better served if such services were performed by electric suppliers. Board shall report its findings along with recommendations not later than 1/1/99 to GA. (p. 11, 42-43, 97)
Illinois **H.B. 362**	Each utility shall continue offering to all residential and small commercial retail customers bundled electric power consistent with bundled service provided on the effective date of the Act. Any residential or small commercial retail customer that buys electricity from an alternative supplier is entitled to return to the utility's bundled, tariffed service offering upon payment of a reasonable administrative fee provided, however, that the utility shall be entitled to impose the condition that such a customer may not elect to purchase energy from an alternative supplier for up to 24 months thereafter. The ICC shall have authority to review, approve, and modify prices, terms and conditions of those components of delivery services not subject to FERC jurisdiction, including authority to determine the extent to which delivery services should be offered on an unbundled basis. The ICC shall investigate the need for and desirability of different or additional unbundling of delivery services for some or all electric utilities 3 years from the date that a tariff or delivery service is first approved. The ICC shall open an additional proceeding to again investigate 3 years after the entry of its final order in the first investigation proceeding. In each proceeding the ICC shall consider at a minimum the effect of additional unbundling on just and reasonable rates, utility employees, and the development of competitive markets. The ICC may upon complaint or its own initiative conduct a hearing concerning the need and desirability of requiring additional or other unbundling of delivery services offered by utilities. The ICC shall have authority to investigate the need for and to require the restructuring or unbundling of prices for tariffed services other than delivery services offered by utilities. (p. 10-11, 17-18, 23-25)
Maine **H-568** **(LD 1804)**	Beginning 1/1/99, utility shall issue bills that state current cost of electric capacity and energy separately from transmission and distribution charges and other charges for electric service. By 1/31/98, each utility shall file unbundling proposal with PUC. Beginning 3/1/02, billing and metering services are subject to competition. PUC may establish earlier date for competitive billing and metering services, but beginning date may not be prior to 3/1/00. (p. 3, 19)
Massachusetts **H-5117**	Consumers can best be served by unbundling of prices and services. On or before 1/1/98, each electric company shall file with DTE detailed plan for restructuring. Plan shall include, among other items, unbundled prices or rates for generation, distribution, transmission and other services. Not later than 6 months after 3/1/98, distribution companies shall create and send bills to retail customers pursuant to either of following billing options: (1) single bill from distribution companies with separately itemized rates for generation, transmission, and distribution services and transition charges; or (2) 2 bills — 1 from nonutility supplier that shows energy-related charges, and 1 from distribution company that shows distribution-related charges. No sooner than 1/1/00, DTE in conjunction with DER is directed to investigate metering, meter maintenance and testing, customer billing, and information

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	services that have been provided by distribution companies since 3/1/98 to analyze and determine whether such services should be unbundled and provided on competitive basis. In event DTE concludes that such services should be subject to unbundling and competition, it shall not later than 1/1/01 file recommendations with House of Representatives. Any unbundling and creation of retail competition for such services shall not commence unless statutorily allowed. (p. 2, 54, 62, 142, 153)
Montana **S.B. 390**	Electrical bills must disclose each component of electrical bill in accordance with rules promulgated by PSC. Bills must disclose distribution and transmission charges, electricity supply charges, competitive transition charges, and universal system benefits charges. (p. 14)
New Hampshire **H.B. 1392**	Restructuring should require unbundling of prices and services. Customers should be able to choose options such as levels of reliability, real time pricing, and generation source. There should be clear price information on generation, transmission, distribution, and ancillary services. (p. 2, 4)
Oklahoma **S.B. 500**	A primary goal of restructured industry is to encourage unbundling of prices. Consumer choice means retail consumers shall be allowed to purchase different levels and quality of electric supply. When consumer choice is introduced, rates shall be unbundled to provide clear price information on generation, transmission, distribution, and ancillary charges. Bills for all classes shall be unbundled, utilizing line itemization to reveal various component costs of services. Charges for public benefit programs shall be unbundled and appear in line item format for all classes of consumers. (p. 3-5)
Pennsylvania **H.B. 1509**	PUC must require unbundling of electric services, tariffs, and bills to separate charges for generation, transmission and distribution, and may require unbundling of other services. Customer bills must contain unbundled charges sufficient to enable consumer to determine basis for charges. (p. 29-30, 47)
Rhode Island **96-H 8124 Substitute B**	On or before 1/1/97, and effective 7/1/97, distribution companies shall file unbundled rates separately stating transmission, distribution and transition charges. Customer bills shall conspicuously display specified information, including transition and conservation charges, taxes, number of kWh consumed, cost of power, cost of distribution, and other costs. (p. 27, 49)
Virginia **H.B. 1172**	
Consumer Education	
Nevada **A.B. 366**	The PUC shall establish minimum standards for form and content of all disclosures, explanations, or sales information disseminated by sellers of competitive services to ensure that consumers receive adequate, accurate, and understandable information about service that enables them to make informed decision relating to source and type of electric service purchased. Such standards must not be unduly burdensome, must not unnecessarily delay or inhibit competition, and may establish different requirements for disclosures, explanations, or sales information relating to different services or similar services to different classes of customers wherever appropriate. Before commencement of direct access, PUC shall carry out educational program for consumers to inform them of changes in provision of electric service, inform them of requirements relating to disclosures, explanations, or sales information, and provide assistance in understanding and using information to make reasonably informed choices. PUC shall expend up to $500,000 from its reserve account to provide education and informational services to educate and inform residents. PUC shall contract with independent person to provide such services. (Section 48, p. 19; Section 57, p. 24)
Arizona **H.B. 2663**	PPEs are responsible for ensuring and overseeing a comprehensive public education program regarding competitive generation. PPEs and the ACC shall coordinate their respective rules and procedures for public education programs to promote consistent implementation statewide. The program shall address the following: educate retail customers about changes in the industry, provide retail customers accurate and unbiased information so they can make informed choices, encourage public participation in decision making, work with interested parties including community-based consumer advocate organizations to develop and implement an outreach and education plan. The ACC's authority to develop and oversee a comprehensive public education program is confirmed. (p. 21-22, 27)
California **H.B. 1890**	Electric corporations, in conjunction with PUC, shall devise and implement customer education program. (p. 72)
Connecticut **Substitute H.B. 5005**	Not later than 12/1/98, DPUC shall develop comprehensive public education outreach program to educate customers about retail competition. Goals of program are to maximize public information, minimize customer confusion, and equip customers to participate in restructured market. Program shall include but not be limited to: (1) dissemination of information through mass media, interactive approaches, and written materials; (2) public forums in different geographical areas to foster public input and exchange information; (3) involvement of community-based organizations; (4) targeted

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	efforts to reach rural, low-income, elderly, foreign-language, disabled, ethnic minority, and other traditionally underserved populations; (5) periodic evaluations of effectiveness of educational efforts. Implementation of outreach program shall begin not later than 1/1/99. Consumer education advisory council shall advise outreach program coordinator. Council shall be composed of government, community, business, and consumer representatives. Council shall determine information to be distributed as part of educational program. DPUC shall adopt regulations developing standard billing format that enables customers to compare pricing, policies, and charges. Each licensed supplier shall submit information to DPUC after consultation with consumer education advisory council to assist customers in making informed decisions. Each supplier shall submit, on quarterly basis, reports containing information DPUC deems relevant to consumers. DPUC shall maintain and make available list of aggregators and information about each supplier regarding rates and charges, terms and conditions of service, and percentage of each supplier's output derived from specific categories of energy sources, including emissions data regarding energy sources. DPUC shall retain consultants to assist in developing public education outreach program. Expenses shall not exceed $350,000. All reasonable and proper expenses accrued prior to 1/1/00 shall be borne by electric companies. After systems benefit charge begins to be collected on 1/1/00, companies shall recover those expenses that have been accrued by companies up until that date through systems benefit charge. On and after 1/1/00, all reasonable and proper expenses shall be assessed directly through systems benefits charge. (p. 35-36, 42, 50, 56)
Illinois **H.B. 362**	All consumers must receive sufficient information to make informed choices among suppliers and services. The ICC shall implement and maintain a consumer education program to provide residential and small commercial customers with information to help them understand service options and rights and responsibilities. The ICC shall form a 10 member working group consisting of 5 representatives of IOUs, 2 representatives of alternative suppliers, 3 representatives of organizations representing residential and small commercial customers, and the ICC. By 3/1/99, the working group shall develop a package of printed educational materials for small commercial customers. A similar package shall be developed for residential customers by 11/1/01. The packages shall be submitted to the ICC for approval along with recommendations for implementing the education program. Such materials shall address needs of the elderly, low-income, multi-lingual, minority, rural, and disabled customers. At a minimum, the material shall include concise explanations of the structure of the utility industry, a glossary of basic terms, choices available to take service from alternative suppliers or remain with utilities, customers' rights, risks, and responsibilities, legal obligations of alternative suppliers, services that may be offered on a competitive basis, services utilities are required to provide pursuant to tariffed rates, components of a bill, complaint procedures, phone numbers of the ICC, attorney general, or other entities that can provide information and assistance. Utilities shall mail materials to all residential and small commercial retail customers within a reasonable period prior to the date these groups become eligible for choice. Alternative suppliers shall include such materials with all initial mailings. Both utilities and alternative suppliers shall provide such materials at no charge to small customers. The ICC shall make such materials available on the Internet. The ICC may adopt a uniform disclosure form alternative sellers must use to enable customers to compare prices, terms, and conditions. The GA shall fund the costs of such ICC services. The ICC shall study the effectiveness of the program and include legislative recommendations in its annual report. Effective 1/1/99, all suppliers shall provide information along with bills on a quarterly basis indicating known sources of electricity supplied, broken out by percentages, pie charts that depict the percentage of the sources and a standardized chart that shows the amounts of various emissions produced in the generation of electricity. All such information shall be included on the ICC Internet site. (p. 3, 63-68, 86-87)
Maine **H-568** **(LD 1804**	PUC shall establish standards for publishing and disseminating, through any means considered appropriate, information that enhances consumers' ability to effectively make choices in competitive market. PUC shall adopt rules implementing consumer education program including immediate organization of consumer education advisory board to investigate and recommend methods to educate public about retail access and its impact on consumers. PUC shall ensure broad representation from all customer classes including public agencies on advisory board. Members serve without compensation. Advisory board must address level of funding for adequate educational efforts and source of such funding; aspects of retail access on which consumers need education; most effective means of accomplishing education of consumers; appropriate entities to conduct education efforts; and any other relevant issue regarding education of consumers. PUC shall consider recommendations of advisory board when adopting rules to implement consumer education program. (p. 5, 19)
Massachusetts **H-5117**	The DER shall plan, develop, oversee, and operate programs to help consumers understand, evaluate, and select retail energy supplies and related services offered as result of restructuring. Commissioner of Division of Capital Planning and Operations is authorized to undertake activities to assist consumers in understanding and evaluating rights and choices in retail market. Said activities shall provide consumers with information that provides consistent and reliable basis for comparing products and services and shall develop activities in cooperation with Attorney General to assist in detection and avoidance of unfair or deceptive marketing practices. Activities may include: (1) development of consumer education materials, including billing inserts, providing consumers with

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	information in clear and consistent manner to enable them to select their own suppliers and products based on individual preferences such as price, resource type and environmental considerations, and whether generation supplier operates under collective bargaining agreements or if such supplier operates with employees hired as replacements during course of labor dispute; (2) collection and dissemination of accurate and comparable information derived from uniform disclosure labeling system that shall identify price of power generation, length and kind of contract, mix of fuel and power generation sources, and level of air emissions. Division may establish and advertise toll-free telephone hotline capable of responding to consumer questions and complaints. Consumer education activity shall be described in plan submitted to House and Senate. Plan shall recommend provision of services funded by state only to extent that private market cannot or does not adequately meet information needs of retail customers. Massachusetts Technology Park Corporation, through its board, shall adopt detailed plan, one of whose components is training and public information to allow for development and dissemination of complete, objective, and timely information, analysis, and policy recommendations related to advancement of public purposes and interests of Renewable Energy Fund. Before service is initiated by generation company, aggregator or supplier, entity shall disclose information on rates and other information to customer in written statement that customer may retain. DTE shall promulgate regulations prescribing form, content, and distribution of such information, which shall include rate to be charged, whether entity operates under collective bargaining agreements or operates with employees hired as replacements during course of labor dispute, any charges, fees, penalties, or other conditions imposed on customer who chooses to select another power supplier during term of contract, fuel mix and emissions of generation sources, whether credit agency will be contacted, deposit requirements and interest paid on deposits, due date of bills and consequences of late payment, consumer rights where bill is estimated, consumer rights of third-party billing, consumer rights to deferred payment arrangements, low-income rates, limits, if any, on warranty and damages, provisions for default services, toll-free telephone number for service complaints, any other fees, charges, or penalties, and methods by which consumer shall be notified of any charges for these items. Entity shall prepare information booklet describing customer's rights under provisions of this chapter and shall annually mail booklet to its customers. Entity shall be allowed to advertise percentage of its power generated by employees operating under collective bargaining agreement and relative environmentally beneficial effects of power sold by entity. Such advertisement shall be pursuant to rules promulgated by DTE. DTE shall also promulgate regulations prescribing information to be disclosed by entity that shall include rate to be charged in bold print or clear-spoken language in case of television or radio advertisements. DTE shall promulgate uniform labeling regulations as condition of licensure. Such labeling information shall include price data, price variability, and customer service information, including whether company operates under collective bargaining agreements or uses employees hired as replacements during course of labor dispute, fuel sources and air emissions. DTE shall, no later than 7/1/98, disclose publicly all rates approved by department prior to 7/1/97, which were not previously disclosed to public and in no manner shall any rate continue to receive nondisclosure status. (p. 15-18, 27, 67-69, 143)
Montana **S. B. 390**	Public utilities shall educate customers about choice so customers can make informed choices. Education process must give special emphasis to efforts during transition period. (p. 5)
New Hampshire **H.B. 1392**	PUC should ensure customer confusion is minimized and consumers will be well informed about changes. (p. 4)
Oklahoma **S.B. 500**	Commission shall ensure that consumer confusion will be minimized and consumers will be well informed about changes resulting from restructuring and increased choice. (p. 4)
Pennsylvania **H.B. 1509**	Each distribution company, in conjunction with PUC, must implement consumer education program. PUC shall establish regulations to ensure suppliers provide adequate and accurate information to enable consumers to make informed choices. Information must be in understandable format that enables comparison of price and service on uniform basis. (p. 47-48)
Rhode Island **96-H 8124 Substitute B**	Distribution companies to notify customers of retail options at least 90 days prior to eligibility for retail access. (p. 25)
Virginia **H.B. 1172**	Commission has authority under existing law to impose requirements on electric utilities to implement programs that educate consumers.
Consumer Protection	

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Nevada **A.B. 366**	Any alternative seller must have PUC license, which may be limited, suspended, or revoked to protect public interest. By 1/1/99, PUC to establish conditions alternative sellers must satisfy before selling to retail customers. Conditions relate to safety, electric reliability, financial reliability, fitness to serve customers, billing practices, and terms for establishing and terminating service. PUC to establish and implement standards of conduct related to activities inconsistent with goals of Act, including appropriate penalties for violation and procedures for imposing such penalties and referring potential violations to Attorney General or Justice Department. PUC shall establish procedures to ensure no customer is switched to another seller without reliable confirmation. (Section 40, p. 14; Section 42, p. 15-16; Section 48, p. 19)
Arizona **H.B. 2663**	The governing body of a PPE shall adopt a code of conduct to prevent anti-competitive activities that may result from the PPE providing both competitive and noncompetitive services to retail customers. The code shall address at least the following issues: policies for allocating costs between competitive and noncompetitive activities to avoid cross-subsidization, policies to prevent employees providing noncompetitive services from directing customers to the PPE's competitive services, policies to prevent transfer of proprietary information gained in noncompetitive sectors to employees engaged in competitive sectors without consent of the customer, policies to provide retail customers with complete and accurate disclosure of which services are competitive and which are noncompetitive, and policies to prohibit preferential treatment when providing noncompetitive services based on a customer's provider of competitive services. The PPE shall have an annual independent audit performed to ensure compliance with the code. The PPE shall provide a dispute resolution process including nonbinding, third-party arbitration or mediation. PPEs shall adopt rules and procedures to protect the public against deceptive, unfair, and abusive business practices. PPEs and the ACC shall coordinate their respective rules and procedures to promote consistent implementation statewide. The rules and procedures adopted by PPEs shall address at least: deceptive, unfair, and abusive practices including deposit requirements and reconnection fees, intrusive and abusive marketing practices, deceptive or untrue advertising, providing an ombudsman to investigate complaints regarding subsidization of competitive services by noncompetitive services and limitations on advertising services of affiliates. The rules shall require separate authorization to change suppliers and plain language in advertising and billing using uniform words and phrases that have the same meanings so customers can make accurate comparisons. The separate authorization shall not contain any inducements, shall be in legible print with clear and plain language confirming the terms and conditions of the service to be provided, shall not state or suggest the customer take action to retain the current supplier. A supplier that executes a change in violation of the rules shall refund to the original supplier the entire amount of the customer's electricity charges for 3 months or the period of unauthorized service, whichever is less. No box or container may be used to collect entries for contests andat the same time be used to collect authorizations to change service. Customer information is confidential unless specifically waived by the customer in writing. During initial construction of a residential structure, electric and natural gas facilities shall both be installed to provide consumer choice unless provision of one of the facilities is not economically feasible. In supervising and regulating PSCs, the ACC's authority is confirmed to adopt rules identical to those applicable to PPEs. An electricity supplier shall obtain a certificate from the ACC before offering retail electric service. The ACC may adopt, amend, and repeal rules reasonably necessary to carry out these provisions. On or before 12/31/98, the ACC shall adopt rules providing minimum standards of disclosure and complaint procedures applicable to certificated suppliers. The ACC may impose conditions on the certification of suppliers to assure the financial stability, including periodic reports, bonds, and deposits. (p. 16-17, 19-20, 22, 24, 27, 32, 35-36)
California **H.B. 1890**	Every entity offering power to small customers must register with PUC. All offers of service must include written notice of price and terms, including amount of CTC and right to rescind contract. Consumers can recover actual and punitive damages, including attorney's fees, for violations. No residential or small commercial customer's account can be switched to another provider without confirmation by independent third-party verification company. (p. 6, 43-44, 72-73)
Connecticut **Substitute H.B. 5005**	Not later than 1/1/99, DPUC shall adopt Code of Conduct applicable to distribution companies. Code shall be effective upon completion of unbundling but not later than 7/1/99. Code shall include: (1) measures to ensure information, revenues, expenses, costs, assets, liabilities, or other resources derived from transmission or distribution shall not be used to subsidize any generation entity or affiliate; (2) safeguards to assure fair dealing between distribution companies and all other electric suppliers; (3) procedures for ensuring nondiscriminatory access to transmission and distribution facilities; (4) measures to ensure that distribution companies apply tariffs in nondiscriminatory manner. Code shall, at minimum: (a) prohibit employee of generation entity or affiliate from conducting distribution operations or having access to system control centers in way that differs from access available to employees of nonaffiliated suppliers; (b) prohibits employees of generation entity or affiliate from having preferential access to information; (c) prohibits employee of distribution company from disclosing information to employee of generation entity or affiliate; (d) requires employees of distribution companies to apply all tariff provisions in fair, impartial, and nondiscriminatory manner; and (e) prohibits joint marketing activities between distribution companies and their generation entities or affiliates. DPUC may enforce code, including cease and desist orders and civil penalties. Any person aggrieved by violation of code also has private right of action. No

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	person shall contract for sale of generation to end-use customer after 1/1/00, unless person has been issued license. No license shall be valid before 7/1/99. After 1/1/00, no person or municipality shall sell generation to end-use customer, and no person shall aggregate, broker, or market electric services unless they have license. Not later than 1/1/99, DPUC shall adopt regulations developing licensing procedure. Licensing process shall begin not later than 4/1/99. To ensure safety and reliability, DPUC shall not issue license unless person can demonstrate technical, managerial, and financial capability and provides bond or other security to ensure financial responsibility. Licensee must be in compliance with all applicable licensing requirements of FERC and must be registered with ISO and be able to demonstrate capacity to provide adequate electricity. DPUC shall require as condition of license that supplier complies with National Labor Relations Act and Connecticut Unfair Trade Practices Act. Licensee must agree to cooperate with other suppliers in event of emergency and must comply with code of conduct. Any person who fails to comply with license condition or violates provisions of act shall be subject to sanctions. To protect customer from unwanted solicitation, each company shall distribute form approved by DPUC, which customer shall submit to distribution company if customer does not want name, address, telephone number, and rate class released to suppliers. On and after 7/1/99, each distribution company must make such information available to all electric suppliers unless customer requests such information not be released. Prior to initiating generation service, each supplier shall provide potential customer with written notice describing rates, air emissions and resource mix of generation, terms and conditions of service, customer's right to cancel service. No supplier shall provide service unless customer has signed service contract. Customer shall have until midnight of third business day to cancel service contract. Supplier shall not advertise or disclose price of electricity in manner to mislead reasonable person. When advertising or disclosing price of electricity, supplier shall disclose distribution company's average current charges, including CTC and systems benefits charge for that customer class. Each supplier shall comply with provisions of federal telemarketing regulations. Any violation shall be deemed unfair or deceptive trade practice. Customer may change suppliers at any time. Supplier may charge reasonable fee approved by DPUC to make change, except customer may make change once in every 12-month period without charge if change occurs at end of customer's regularly scheduled meter reading and billing cycle. No supplier may discriminate on basis of age, race, creed, color, national origin, ancestry, sex, marital status, sexual orientation, lawful source of income, disability, or familial status. Service can't be terminated and reinstatement can't be refused except in accordance with statutes. Distribution companies can't change customer's supplier unless change has been confirmed by: (1) independent third-party telephone verification; (2) receipt of written confirmation received in mail after customer has received information packet; (3) customer signing document fully explaining nature and effect of change; or (4) customer's consent obtained through electronic means. DPUC is responsible for receiving and acting upon customer inquiries and complaints and shall establish toll-free telephone number for such purposes. DPUC shall monitor market and take actions to prevent unfair or deceptive trade practices, anti-competitive or discriminatory conduct, and unlawful exercise of market power. DPUC shall conduct investigation of any potential anti-competitive or discriminatory conduct or unfair or deceptive trade practices. Investigations may include effect of mergers, consolidations, acquisitions, and dispositions of assets. Attorney General and CC have right to participate in such investigations. If DPUC finds violations of federal or state law, it shall transmit findings along with supporting information to enforcement officials. (p. 33-34, 43-53, 98)
Illinois **H.B. 362**	Consumer protections must be in place to ensure all customers receive safe, reliable, affordable, and environmentally safe electric service. Any alternative supplier must obtain a certificate of authority from the ICC. An applicant shall possess sufficient technical, financial, managerial resources and ability to provide the service it seeks certification for. In reviewing the application, the ICC shall consider characteristics, including size and financial sophistication of the customers the applicant seeks to serve, whether the applicant seeks to provide power using facilities that it controls or operates, and the ICC shall ensure that the applicant complies with all applicable federal, state, regional, and industry rules, policies, practices, and procedures to ensure safety, integrity, and reliability. The ICC has authority to promulgate rules and regulations to carry out the provisions on consumer protection. On or before 5/1/99, the ICC shall adopt rules applicable to certification of alternative suppliers seeking to serve only nonresidential retail customers with maximum demands of 1 mW or more. Requirements may include posting of a bond or letter of credit from a responsible surety or financial institution of sufficient size for the nature and scope of services to be provided and demonstration of adequate insurance as well as experience in providing similar services in other jurisdictions. An alternative seller shall obtain verifiable authorization from a customer in a form approved by the ICC before a customer is switched from another supplier. Alternative suppliers shall not deny service to customers or groups nor establish different terms and conditions based upon race, gender, or income. Alternative sellers may not deny service based on locality, or establish unreasonable price differences between localities. Any marketing materials which make statements concerning prices, terms, and conditions shall contain information that adequately discloses the prices and terms and conditions. Before switching a customer, an alternative supplier shall give the customer written information that adequately discloses, in plain language, prices, terms, and conditions being offered. Alternative sellers shall provide documentation to the ICC and to customers substantiating any claims regarding technologies and fuel types. Alternative suppliers shall supply itemized billing statements describing the products and services, including prices, and an

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	additional statement, at least annually, disclosing average monthly prices and terms and conditions. The ICC has oversight of alternative suppliers to entertain and dispose of any complaints alleging violations of applicable provisions. ICC authority includes the ability to issue cease and desist orders, impose financial penalties not to exceed $10,000 per occurrence or $30,000 per day, and to alter, modify, revoke, or suspend a certificate of authority. Upon request and payment of a reasonable fee, a utility shall provide customers with billing and usage data. Residential and small commercial customers shall not be required to take additional metering services unless the ICC finds that such services are required to meet reliability requirements. If more than 30,000 customers of a utility are subjected to continuous power interruption of 4 hours or more that results in power less than 50 percent of the standard voltage, utility must compensate customers for all actual damages unless the utility can show that the outage was due to unavoidable causes. In the event of a power surge that affects more than 30,000 customers, a utility shall reimburse customers for the replacement value of all goods damaged as a result unless the utility can show that the surge was due to unavoidable causes. A utility shall make reasonable efforts to notify potentially affected customers no less than 24 hours in advance of scheduled maintenance. To obtain certification, an alternative supplier must demonstrate to the ICC that its employees have the requisite knowledge, skills, and competence to perform installation, operation, and maintenance functions for generation, transmission, or distribution facilities. The ICC shall not approve any proposed reorganization if it finds that the reorganization will adversely affect the utility's ability to perform its duties or that the proposed reorganization will have significant adverse impacts on competition or adverse rate impacts on retail customers. The health, welfare, and prosperity of state's citizens requires effective public representation by the attorney genera (AG)l. A consumer utilities unit is created within the office of the attorney general. The unit shall have the power and duty to intervene in, initiate, enforce, and defend all legal proceedings relating to provision, marketing, and sale of electric service whenever the AG determines such action is necessary to promote or protect the rights and interests of citizens. The AG shall be a party as a matter of right to all proceedings and investigations before the ICC and shall have access to and use of all files, records, data, and documents in the possession or under the control of the ICC. An electric provider shall not submit or execute a change in a subscriber's selection of provider without a written authorization using a letter of agency that meets specified requirements. The letter must be a separate document, signed and dated by the subscriber. The letter shall not be combined with inducements of any kind on the same document. The letter shall contain in easily readable, boldface type on the face a notice that the consumer is authorizing a provider change. The letter must contain clear and unambiguous language that confirms the subscriber's billing name and address, the decision to change providers, the terms, conditions, and nature of the service to be provided, and the rate for service. The subscribed must be advised that the change may involve a charge. The letter shall not suggest or require that the subscriber take some action to retain the current provider. Violations in advertising, sale, provider selection, billing, or collections that involve elderly persons or disabled persons may be punished with a civil penalty of $50,000 for each violation. Any advertisement that lists rates shall clearly and conspicuously disclose all associated costs for the service including but not limited to access fees and service fees. Bills must display the name, toll-free telephone number of the provider, and a description of the services provided on all bills. All personal information shall be used solely for the purpose of generating the bill and shall not be divulged to any other person except credit bureaus, collection agencies, and persons licensed to market electricity in the state, without the written consent of the subscriber. (p. 3, 54-64, 70, 73-74, 78-80, 88, 149-150, 217-222)
Maine **H-568** **(LD 1804**	PUC shall establish minimum standards to protect consumers. PUC shall license competitive electric providers. To issue license, PUC must receive evidence of financial capability, ability to enter into binding interconnection arrangements with transmission and distribution utilities, disclosure of all pending legal actions and customer complaints filed during prior 12 months, evidence of ability to satisfy renewable resource portfolio standards, and disclosure of names and corporate addresses of all affiliates. PUC may also require bond as evidence of financial ability to withstand market disturbances. PUC shall establish rules governing information disclosure for competitive providers. As condition of licensure, provider supplying customers with demand of 100 kW or less may not terminate generation service without 30 days' prior notice, must offer service for minimum period of 30 days, must allow customer to rescind selection of competitive provider within 5 days of initial selection, may not telemarket services to customer who has filed written request not to receive such services, and must provide customer with specified disclosure information within 30 days of contracting. PUC may limit duration and scope of license or may revoke license in public interest. PUC shall establish by rule consumer protection standards to protect and promote market competition and to prevent fraud or other unfair and deceptive business practices. PUC may impose penalty of up to $5,000 for each violation of any consumer protection rule. Each day of violation constitutes separate offense. If PUC has reason to believe that utility has violated any provision of law for which criminal prosecution is provided or has violated any antitrust law of state or US, PUC shall notify attorney general. Attorney general shall promptly institute any appropriate actions. Distribution utility may not release any proprietary customer information without prior written authorization of customer. Employees of distribution utility may not state or provide any customer or potential customer opinion regarding reliability, experience, qualifications, financial capability, managerial capability, operations capability, customer service record, consumer practices, or market share of any affiliated competitive provider or nonaffiliated competitive provider. (p. 4-6, 9-10, 12)

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Massachusetts H-5117	The DER shall intervene and advocate on behalf of small commercial and industrial users before DTE in any dispute between such businesses and generation or distribution companies. Commissioner of DER in conjunction with Attorney General is authorized to undertake activities to assist in detection and avoidance of unfair or deceptive marketing practices. DER shall annually issue report containing information on all issues of reliability, including generation and transmission data detailing load and capacity, forecasting potential future capacity excesses or deficits for next 5 years. Report shall contain electricity spot-price information, extent to which energy markets are maintaining necessary levels of reliability, whether or not all customers classes are being adequately served by competitive markets, determination of competitiveness of energy markets including determination of whether consumers are receiving lowest possible prices within competitive market and determination of extent to which markets are achieving efficiency and fuel diversity goals. Report shall identify any substantial fluctuation or pricing differences with respect to geographic regions and low- and moderate-income consumers. Report shall make recommendations for improving deficiencies. DTE shall establish service quality standards. Each distribution and transmission company shall file report with DTE by 3/1 of each year comparing its performance during prior calendar year to service quality standards and any applicable national standards adopted by DTE. DTE shall levy penalty against company that fails to meet service quality standards in amount up to and including 2 percent of such company's transmission and distribution service revenues for previous calendar year. DTE shall establish alternative dispute resolution process for claims by customers under $100. All mediation claims must be resolved within 60 days. DTE shall promulgate regulations to provide retail customers with utmost consumer protections contained in law including licensing of generation companies, aggregators, suppliers, energy marketers and energy brokers. DTE shall maintain list of all licensed companies. License application shall require information on company's technical ability, documentation of financial capability, description of company's form of ownership, and documentation regarding purchase power contracts between company and its affiliates or its parent. All private, nonprofit or cooperative aggregators shall submit license application. DTE rules shall include provisions that all entities notify their customers in writing of terms of services agreements, formal procedure allowing customer to file complaint against supplier, formal dispute resolution procedure developed in consultation with Massachusetts Office of Dispute Resolution (ODR), which shall include options for mediation, arbitration, facilitation, or other dispute resolutions. DTE or neutral professional provided by ODR will assist in resolving disputes between customers and suppliers subject to penalty determined by DTE, including fines. No distribution or generation company may disconnect for disputed amount if customer has complaint pending with DTE. DTE shall establish regulations to promote effective competition, investigate disputes, institute complaint mechanisms for dispute resolution including those arising from alleged vertical or horizontal market power abuses, hear disputes at informal level and, if necessary, at formal hearing, refer complaints to Attorney General and impose fines or penalties for violations of corporate rules of conduct. DTE shall promulgate uniform labeling regulations as condition of licensure that shall include price data, price variability, customer service information, and whether company operates under collective bargaining agreement or operates with employees hired as replacements during labor dispute. Labeling requirement shall also disclose fuel sources and air emissions. DTE shall establish Code of Conduct including confidentiality of customer records, metering, billing and information systems, and conformance with fair labor practices. DTE shall oversee quality and reliability and require quality and reliability at same or better levels than existed on 11/1/97. DTE shall promulgate rules to establish service quality standards for distribution and transmission companies relating to universal service, customer satisfaction, service outages, billing service, and public and employee safety. Any person or firm who violates provision of code or any rule or regulation of DTE shall be subject to civil penalty not to exceed $25,000 for each violation for each day with a maximum civil penalty not to exceed $1 million for any related series of violations. Each customer choosing company shall be required to affirmatively choose such entity. It shall be unlawful to provide power or other services without first obtaining affirmative choice of customer. Affirmative choice means letter of authorization, third-party verification, or toll-free call by customer to independent third party physically separate from telemarketing representative who obtained customer's initial oral authorization. Authorization must include appropriate verification data and shall not be used for any commercial or marketing purposes and shall not be sold or shared with another entity. Letter of authorization must be separate document whose sole purpose is to authorize company to supply power or to initiate change. Letter must be signed and dated and must not be combined with inducements of any kind on same document. Letter must be printed with readable type, be clearly legible, and contain clear and unambiguous language that confirms customer's name and address, decision to change, that customer understands service may be provided by only one company, that consumer understands there may be charge involved for changing suppliers, and letter may not suggest consumer should take some action to remain with current supplier. Each customer shall have right to rescind change order without penalty no later than midnight on third day following written confirmation. Upon switching, customer's first bill must include acknowledgement to be completed by customer agreeing to service switching. Customer may initiate complaint that service has been switched without his prior authorization. If DTE determines new provider does not possess required authorization, DTE shall require provider to refund to customer difference between what customer would have paid to prior provider and actual charges paid to new provider, any reasonable expense customer incurred in switching back, and original provider's lost revenue. Any company determined by DTE to have switched customer's service one or more times in 12-month period shall be subject to penalty not to

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	exceed $1,000 for first offense and not less than $2,000 nor more than $3,000 for any subsequent offense per customer. Any company determined to have switched customer service more than 20 times in 12-month period may be prohibited from selling electricity for period up to one year. DTE shall keep record of all unauthorized switches during calendar year. Beginning in 1999, DTE shall by 3/31 of each year file annual report detailing total number of unauthorized switches, enforcement procedures, and total amount of dollars returned to customers as well as total amount of dollars collected in civil penalties. All companies shall submit to arbitration if requested by retail customer any allegation of unfair or deceptive trade practice. DTE shall promulgate regulations to implement this procedure and rule shall include opportunity to participate in voluntary mediation without recourse to arbitration. (p. 18-19, 62-74, 121)
Montana **S.B. 390**	Public interest requires continued protection of consumers through licensure, provision of information, and process for investigating and resolving complaints. Utilities shall maintain standards of safety and reliability of electric delivery system. PSC may require proof of financial integrity, adequate reserves, and license bond. PSC may revoke or suspend license of electric supplier or impose penalty or both. If supplier intentionally provided false information to PSC, switched electricity customer without written permission, failed to provide reasonably adequate supply of electricity, committed fraud, or engaged in deceptive practices, fine is not less than $100 or more than $1,000 for each violation. Each day of each violation constitutes separate violation. PSC shall promulgate rules establishing procedures to prevent unauthorized switching of customers. Transitional advisory committee shall file annual report in 2000 that addresses need, if any, for additional consumer protection including protection from abusive or anticompetitive practices. (p. 1, 11, 13-14, 16)
New Hampshire **H.B. 1392**	Retail suppliers who do not own transmission and distribution facilities should at minimum be registered with PUC. (p. 5)
Oklahoma **S.B. 500**	Appropriate rules shall be promulgated ensuring that reliable and safe electric service is maintained. Minimum residential consumer service safeguards and protections shall be ensured. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring including but not limited to reliability and safety. Final report shall be provided to legislative task force no later than 12/31/98. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of consumer safeguards and licensing of retail suppliers. Final report shall be provided to legislative task force no later than 8/31/00. All retail suppliers shall be required to meet certain minimum standards designed to ensure reliability and financial integrity and be registered with Commission. There shall be no customer switching between distribution providers from date of this Act until 7/1/02, except by mutual consent of all affected parties. (p. 4-7, 9)
Pennsylvania **H.B. 1509**	Each generation supplier required to obtain PUC license and post bond or other security to ensure financial responsibility. PUC to establish regulations to prevent customer account transfer without direct oral confirmation or written consent. PUC to monitor market for anti-competitive conduct; investigate complaints or potential violations and refer them as necessary to appropriate state or federal prosecutors; deny proposed mergers, acquisitions, dispositions, or other transactions that are anticompetitive or discriminatory. (p. 21, 47, 53, 67-69)
Rhode Island **96-H 8124 Substitute B**	By 1/1/97, electric licensing committee to submit proposals to legislature for consumer protection. All nonregulated power producers must file registration application with division listing specified information and showing evidence of financial soundness such as surety bonds or other mechanisms specified by division. On request, distribution company must release names and addresses of customers to power producers who will be eligible for retail access within next 60 days, unless customer has requested in writing that information not be released. (p. 22, 24, 26)
Virginia **H.B. 1172**	Commission has authority under existing law to impose requirements on electric utilities to implement programs that benefit public health, safety, and welfare.
Universal Service/Low-Income Assistance Program	
Nevada **A.B. 366**	An electric distribution utility shall provide all noncompetitive services within its territory unless PUC authorizes another entity to provide noncompetitive service. PUC to establish minimum terms and conditions under which any customer not using alternate seller will receive electric service. PUC shall designate utility to provide service to customers who do not elect or are unable to obtain alternative seller. Procedures may include, but are not limited to, requiring utility to serve such customers, requiring each alternative seller to serve share of such customers, competitive bidding to select one or more providers. If provider is electric utility, service shall be provided through affiliate whose sole business is provision of basic service. (Section 44, p. 17; Section 45, p. 18)
Arizona **H.B. 2663**	PPEs shall adopt reasonable terms and conditions governing the electric distribution utility's obligation to provide electric distribution and other services. The PPE that has a service territory through a

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	certificate of convenience and necessity, resolution, or contracts or agreements among utilities shall act as the supplier of last resort for electric generation service for every retail customer within the service territory whose annual usage is 100,000 kWhs or less or whose generation service has been discontinued through no fault of the customer, if other electric suppliers are unwilling or unable to supply generation service. PPEs that provide distribution services are entitled to recover just and reasonable costs for supplying generation service through a distribution charge on retail customers whose annual usage is 100,000 kWhs or less. PPEs and the ACC shall coordinate their respective rules and procedures to provide statewide uniformity. These provisions are subject to legislative review by the auditor general in 08. The review shall include recommendations on whether electric distribution utilities shall remain the provider of last resort or if other electric suppliers should bid to be the provider of last resort. (p. 17, 21)
California **H.B. 1890**	Such programs must continue to be funded at not less than 1996-authorized levels. (p. 6, 65-67)
Connecticut **Substitute H.B. 5005**	Public policy measures including winter moratorium and hardship provisions should be preserved. Restructured market must provide adequate safeguards to assure universal service. DPUC shall establish systems benefits charge imposed against all end-use customers beginning 1/1/00. DPUC shall conduct hearing to establish systems benefits charge. System benefits charge shall be used to fund, among other things, hardship protection measures, bill payment programs, and weatherization programs. Systems benefits charge shall be determined in general and equitable manner and shall be imposed on all end-use customers at rate that is applied equally to all customers of same class. Any municipal electric utility created on or after 7/1/98 and any municipal electric utility that expands its service area after that date shall collect systems benefits charge. On and after 1/1/00, each distribution company shall make available to all customers in its service area standard offer. Under standard offer, customer shall receive rate established by DPUC and each distribution company shall provide services to any customer who affirmatively chooses standard offer services or does not or is unable to arrange for or maintain electric generation services. Standard offer automatically terminates on 1/1/04, unless extended by GA. Not later than 10/1/99, DPUC shall establish standard offer, effective 1/1/00. On and after 1/1/04, each distribution company shall serve any customer who does not or is unable to arrange for or maintain generation service. Distribution company shall procure generation services for such customers through competitive bidding process. On and after 1/1/00, and until ISO implements procedures for backup power, each distribution company shall provide generation services to any customer whose supplier fails to provide services for reasons other than customer's failure to pay. Between 1/1/00 and 12/31/03, distribution company may procure generation services through competitive bidding process or through its own generation facilities or affiliates. On and after 1/1/04, distribution company shall procure generation services through competitive bidding process. As condition of licensure, DPUC shall prohibit each supplier from declining to provide service to customers located in economically distressed area. No supplier may refuse service for sole reason that customer is located in economically distressed geographic area or because customer qualifies for hardship status. From 11/1 to 4/15 of any year, no distribution company or municipal utility shall terminate or refuse to reinstate residential electric service in hardship cases where customer lacks financial resources to pay entire account. As part of investigation into new pricing principles and rate structures, DPUC shall determine whether existing or future rate structures place undue burden upon persons of poverty status and shall make such adjustment in rate structure as is necessary or desirable to take account of their indigency. DPUC and CC shall conduct joint study on how best to structure program providing service to customers who do not or are unable to arrange for or maintain generation services. Study shall consider following options: (1) distribution company shall be responsible for procuring generation services for default customers through competitive bid, and bidding shall be supervised by DPUC; (2) if there are no qualified bidders, distribution company shall supply generation services and costs will be recovered through systems benefits charge; (3) suppliers who choose not to carry default customers shall be assessed proportionate share of cost of providing default service; (4) whether state agency should be responsible for procuring generation services for default customers. Objective in establishing program for default service shall be achievement of lowest possible cost and maintenance of highest quality service. (p. 7-8, 37-41, 46, 51, 59, 81, 97)
Illinois **H.B. 362**	A utility shall continue offering to retail customers each tariffed service offered on the effective date of the Act until the service is declared competitive. Municipal systems or electric cooperatives shall be required to provide delivery services on their respective systems to the electric utilities in whose service areas the proposed service will be offered. Each shall continue to provide the exclusive distribution facilities for any existing and future customers that the co-op or muni system is now or in the future otherwise entitled to serve and which customers now or in the future receive service provided by an alternative supplier. Beginning 1/1/98, each utility and alternative supplier shall annually contribute a pro rata share of $3 million, based upon the number of kWhs sold. These funds shall be placed in the Energy Efficiency Trust Fund. The funds shall be disbursed to promote energy efficiency projects including but not limited to energy-efficiency efforts for low-income households. The Department of Commerce and Community Affairs shall conduct a study of other possible energy efficiency improvements and evaluate methods for promoting energy efficiency and conservation, especially for the benefit of low-income customers. A Supplemental Low-Income Energy Assistance

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	Fund is created. The department shall use money from the fund for payments to electric or gas utilities or muni systems or electric co-ops on behalf of customers who participate in a program authorized by the department. Each utility, co-op, and mini delivering electric service or natural gas shall assess each of its customers, commencing 1/1/98, a monthly Energy Assistance Charge to support the fund. The monthly charge is 40 cents for each residential account for gas, and 40 cents for each residential electric account; $4 per month for each nonresidential electric account and a similar amount for each gas account; $300 per month on each account for nonresidential electric service exceeding 10 mWs; and $300 per month on each nonresidential gas service using 4 million or more therms of gas. These charges only apply to customers if the utility, co-op or muni make an affirmative decision to impose the charge. An Energy Assistance Program Design Group is established to design a low-income energy assistance program for the period beginning 1/1/03. The group shall be established by the GA or a joint committee thereof. The group shall provide a report with recommendations to the GA on or before 1/1/02. The report must include recommendations defining an eligible low-income residential customer, recommendations regarding the continuation of the program, recommendations ensuring low-income residential customers have access to essential energy services, recommendations addressing past due amounts owed to utilities by low-income individuals, demographic and other information necessary to determine total number of customers eligible for assistance, recommendations to encourage conservation, efficiency, and responsibility among low-income customers, any recommended changes to existing legislation and an estimate of the cost of implementing the recommendations. Some provisions sunset 10 years after the effective date unless renewed by the GA. (p. 10, 94-96, 245-246, 251-257)
Maine **H-568** **(LD 1804**	The policy of state is to ensure adequate provision of financial assistance. In order to continue existing levels of financial assistance for low-income households and to meet future increases in need, PUC shall receive funds collected by all transmission and distribution utilities at rate set by commission in periodic rate cases and set initial funding for programs based on assessment of aggregate customer need. If legislature appropriates financial support for households and individuals receiving assistance from general fund, PUC may not terminate assistance provided by transmission and distribution utilities unless general fund source has completely replaced such assistance. On or before 1/1/98, PUC and state planning office shall provide legislature with recommendations to fund assistance to low-income consumers through general fund or through tax on all energy sources in state. (p. 19-20, 26)
Massachusetts **H-5117**	The state should ensure universal service programs are appropriately funded. Bills for low-income residents should remain as affordable as possible. Beginning on 3/1/98, and for period of 5 years thereafter, DTE is required to charge per kWh charge for all consumers, except those served by municipal plant, to fund energy-efficiency activities, including demand-side management (DSM) programs. At least 20 percent of amount expended for DSM programs by each distribution company in any year, and in no event less than amount funded by charge of 0.25 mils per kWh, which charge shall also be continued in years subsequent to 2002, shall be spent on comprehensive, low-income residential DSM and education programs. Programs shall be implemented through low-income weatherization and fuel assistance program networks. DTE shall define service territories for each distribution company by 3/1/98, based on service territories actually served on 7/1/97, and following to extent possible municipal boundaries. After 3/1/98, distribution company shall have exclusive obligation to provide distribution service to all retail customers within its service territory. Each distribution company shall provide standard service transition rate to those customers within its service territory who choose not to purchase electricity from alternative seller after 3/1/98. Beginning 3/1/98, each distribution company shall provide default service and shall offer default service rate to customers who have chosen electricity service from nonutility affiliated generation company or supplier but who require service because of failure of such company. Distribution company shall procure such service through competitive bidding. Default service rate shall not exceed average monthly market price of electricity. DTE may authorize alternate generation company or supplier to provide default service if it is in public interest. DTE shall ensure universal service for all rate payers and sufficient funding to meet need thereof. On or before 1/1/98, each electric company shall file detailed plan for restructuring with DTE. Among other things, plan shall include proposed programs to provide universal service for all customers. DTE shall require distribution companies to provide discounted rates for low-income customers comparable to low-income discount rate in effect prior to 3/1/98. This discount shall be in addition to any reduction in rates otherwise effective under this Act. Cost of such discounts shall be included in rates charged to all other customers. Each distribution company shall guarantee payment to generation supplier for all power sold to low-income customers at discounted rates. Each distribution company shall conduct substantial outreach efforts to make low-income discounts available to eligible customers. DTE shall consider whether to modify discount by establishing sliding-scale, low-income discount program. There shall be no charge to any residential customer for initiating or terminating low-income discount rates, default service, or standard offer service when initiation or termination request is made after regular meter reading has occurred and customer is in receipt of results of reading. DTE shall promulgate rules to establish service quality standards for, among other things, universal service. Any municipal load aggregation plan shall provide for universal access. (p. 2-3, 12, 48, 54, 58, 60, 65-67, 70, 122)

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Montana **S.B. 390**	Universal system benefits programs include cost effective local energy conservation, low-income customer weatherization, renewables and low-income energy assistance. Programs are paid for by nonbypassable universal system benefits charge assessed at meter. Programs are established to ensure continued funding of, and new expenditures for, conservation, renewables, and low-income assistance during transition period and into future. From 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for calendar year ending 12/31/95 establishes minimum annual funding level. Utilities receive credit for internal programs or activities that support renewables, conservation, or low energy assistance. Credits can be carried forward to future years. Minimum annual funding for low-income and weatherization is established at 17 percent of utility's annual universal system benefits funding level. Utility's transition plan must describe proposals for benefit programs, including methodologies such as cost effectiveness and need determination used to measure utility's level of contribution to each program. Customers with loads greater than 1000 kW pay charge equal fo lesser of $500,000, less credits, or .9 mills per kWh x customer's kWh purchases, less credits. Utilities must submit annual summary report relating to system benefit programs to PSC and transition advisory committee. Co-ops may collectively pool statewide credits to satisfy annual funding requirements. On or before 7/1/02, transition advisory committee and PSC shall reevaluate system benefits programs and make recommendations to legislature regarding future need for such programs. On or before 11/1/98, transition advisory committee shall make recommendations to governor and legislature regarding low-income assistance programs. Recommendations may include assignment of agency or private nonprofit entity to administer fund. (p. 2-4, 11-12, 16)
New Hampshire **H.B. 1392**	Distribution utility has obligation to connect all customers and to maintain minimum residential service safeguards, including low income assistance. Nonbypassable, competitively neutral system benefits charge applied to distribution may be used to fund low income programs. (p. 5)
Oklahoma **S.B. 500**	"Public benefit programs" means all social, economic, and environmental programs currently funded through rates charged to consumers. Entities providing distribution services shall be relieved of their traditional obligation to provide electric supply but shall have continuing obligation to provide distribution service to all consumers within existing service territories. Firm service territories shall be fixed by date certain if not currently established in law. Minimum residential consumer service safeguards and protections shall be insured including programs and mechanisms that enable residential consumers with limited incomes to obtain affordable essential electric service and establishment of default provider for any distribution customer who has not chosen alternative supplier. Commission shall consider establishment of distribution access fee assessed to all consumers to cover social costs, capital costs, and operating costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring including but not limited to stranded benefits and their funding. Final report shall be provided to legislative task force no later than 12/31/99. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect. Final report shall be provided to legislative task force no later than 8/31/00. (p. 3, 5, 7)
Pennsylvania **H.B. 1509**	State must at minimum continue current protections and policies to assist low-income customers. PUC shall ensure that universal service is appropriately funded in each distribution territory and shall encourage use of community-based organizations with necessary experience to be direct providers of programs that assist low-income customers. PUC shall establish appropriate cost recovery mechanism for each utility to fully recover universal service costs. Distribution company remains provider of last resort unless PUC approves alternative. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. (p. 20, 22, 28, 34-35, 48-49)
Rhode Island **96-H 8124 Substitute B**	Current special rates and protections shall continue. Within 3 months after 40 percent of kWh sales in New England are available for retail access, distribution company shall arrange last resort power supply for customers unable to receive power under standard offer or elsewhere. Company shall periodically solicit bids for power at market prices plus fixed contribution from company, subject to PUC approval. Company's fixed contribution is recoverable in rates charged all other customers. Company can terminate for nonpayment pursuant to PUC regulations. Authorized performance-based rate increases for distribution companies between 1/1/97 to 12/31/98 cannot be applied to low-income customers. (p. 3, 27-28, 35, 43)
Virginia **H.B. 1172**	
Renewable Energy, Conservation, and Environmental Issues	
Nevada **A.B. 366**	The PUC shall establish portfolio standards for domestic energy that set forth minimum percentage of total electricity sold during each calendar year that must be derived from renewable energy resources. Portfolio standards must require two-tenths of 1 percent of total amount of electricity annually consumed by customers in this state as of 1/1/01 to come from renewables. This standard

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	must be increased biannually thereafter by two-tenths of 1 percent of total annual electric consumption until standard reaches total of 1 percent of total amount of electricity consumed. Electricity must be derived from not less than 50 percent renewable energy resources and be derived from not less than 50 percent solar renewable energy systems. Tradeable renewable energy credits are allowed. Reporting requirements are established to ensure that all providers comply with standards. A vertically integrated electric utility that has 9 percent of its electricity furnished by renewable energy resources on 1/1/97 is deemed to be in compliance until 1/1/05. Between 1/1/05 and 12/31/09, such utility shall reach total of one-half of 1 percent of annual amount of electricity consumed, in annual increments of one-tenth of 1 percent, from solar energy resources. (Section 52, p. 22-23)
Arizona **H.B. 2663**	
California **H.B. 1890**	PUC must require each electric corporation to identify rate component to fund energy efficiency, public interest research and development, and demand side management in specified yearly amounts that total $540 million through 3/31/02. Funds are to be held by Energy Commission until further legislative action. Consumers can make voluntary contributions through their monthly bills to support such programs. (p. 6, 61-67)
Connecticut **Substitute H.B. 5005**	Renewable energy sources are categorized as either Class I or Class II. Class I includes solar, wind, fuel cells, landfills, or biomass facilities commencing operation on or after 7/1/98. Class II are trash-to-energy, biomass facilities that do not meet criteria for Class I, and hydropower. As matter of public policy, renewable energy incentives should be preserved. Generation should minimize environmental impacts. Consumer Education Advisory Council in consultation with Connecticut Academy of Science and Engineering and New England Conference of Public Utility Commissioners shall analyze environmental costs and benefits of specified categories of energy sources. DPUC shall collect systems benefits charge that shall be used in part to fund weatherization and low-income conservation programs. In order to obtain license, electric supplier must demonstrate supplier's generations facilities located in North America comply with regulations adopted by Commissioner of Environmental Protection and that supplier complies with portfolio standards specified in act. Not later than 1/1/99, Commissioner of Environmental Protection shall establish uniform performance standards for generation facilities designed to improve air quality and to further National Ambient Air Quality Standards. Such performance standards shall be based on fuel used and shall apply to electric suppliers' generation facilities located in North America. Standard shall limit amount of air pollutants emitted per megawatt hour produced and may provide for tradable emissions credits. Performance standard shall go into effect when 3 of states participating in Northeastern States Ozone Transport Commission, with total population of not less than 27 million, have adopted such standard. To be licensed, supplier shall demonstrate that not less than 0.5 percent of its total electricity output is generated from Class I renewables and additional 5.5 percent from Class I or Class II renewable sources. Respectively, percentages must be as follow: on and after 7/1/01, 0.75 percent and 5.5 percent; on 7/1/02, 1 percent and 5.5 percent; on 7/1/03, 1.5 percent and 5.5 percent; on 7/1/04, 2 percent and 6 percent; on and after 7/1/05, 2.5 percent and 6 percent; on or after 7/1/06, 3 percent and 6 percent; on 7/1/07, 4 percent and 6 percent; on 7/1/08, 5 percent and 6 percent; and on 7/1/09, 6 percent and 7 percent, respectively. On and after 1/1/00, DPUC shall charge 3 mils per kWh to each end-use customer to implement program for conservation and load management. Each distribution company shall establish Energy Conservation and Load Management Fund, which shall be separate from all other accounts. DPUC shall appoint energy conservation management board to be composed of representatives from environmental groups, Attorney General and CC, Department of Environmental Protection, distribution companies, and various statewide business and residential customer organizations. Board shall advise and assist distribution companies in development and implementation of comprehensive plan, approved by DPUC, to implement cost-effective energy conservation and market transformation programs. Programs shall be screened through cost-effectiveness testing to ensure energy savings value which is greater than cost of programs . Such programs may include: (1) conservation and load management programs; (2) research, development, and commercialization of more energy-efficient products; (3) market development for such products; (4) energy use assessment and building renovation; (5) design, manufacture, commercialization, and purchase of energy-efficient appliances; (6) program planning and evaluation; and (7) public education regarding conservation. Department may retain consultants for these purposes. On and after 1/1/00, each supplier shall give credit for any electricity generated by residential customers from Class I source. Distribution companies shall make necessary interconnections, including provision of metering equipment. After 1/1/00, DPUC shall assess charge of not less than one-half of 1 mil per kWh, charged to each end-use customer to be deposited in Renewable Energy Investment Fund. The fund shall be administered by Connecticut Innovations, Inc., to promote renewable energy sources and commercialization of such sources, including deployment of renewable sources. Expenditures may include grants, direct investments, contracts for research, development, manufacture, commercialization deployment and installation. Connecticut Innovations, Inc., shall convene renewable energy investments advisory committee consisting of not more than 12 individuals with expertise in various areas of renewable energy resources. Specified members of committee shall be appointed by specified members of legislature and Governor. Certain restrictions on construction of generation facilities are imposed if siting of facility would pose

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	substantial adverse environmental effect. Certificate for facility shall not be granted unless it is determined that public benefit exists for facility and determination has been made of nature of probable environmental impact, including specification of every significant adverse and beneficial impact that may conflict with policies of state concerning environmental issues. DPUC shall examine and regulate transfer of existing assets and franchises and expansion of plant and equipment to ensure that rates, charges, conditions of service, and categories of service do not discriminate against customers which utilize renewable energy sources or co-generation technology to meet portion of their energy requirements. DPUC shall investigate pricing principles and rate structures to consider proposals for energy conservation. In proceeding for rate amendment proposed by distribution company based upon alleged need for increased revenues to finance expansion, DPUC shall determine whether demand-side management would be more cost effective. Connecticut Siting Council shall examine siting procedures and determine how procedures should be modified in restructured industry to consider environmental concerns about green fields, development of new transmission grids, and reliance on high air polluting, out-of-state generation. Not later than 10/1/99, and annually thereafter, each supplier shall report to DPUC and Department of Environmental Protection information regarding: (1) total megawatt hours produced; (2) total megawatt hours purchased; and (3) the proportion of such production derived from nuclear fuels, oil, coal, natural gas, hydro power, and other fuels for amount of emissions. (p. 4-5, 7-8, 36-37, 44-48, 53-55, 69-71, 75, 78, 80-82, 90, 96, 100)
Illinois **H.B. 362**	The use of renewable resources and energy efficiency resources should be encouraged in competitive markets. Effective 1/1/99, every utility and alternative supplier shall provide information, to the maximum extent practicable, with bills to customers on a quarterly basis identifying known sources of electricity supplied, broken out by percentages showing biomass, coal-fired, hydro, natural gas, nuclear, oil-fired, solar, wind, and other resources, respectively. Pie charts that graphically depict the percentages of the sources must be used. Additionally, bills to customers should contain a standardized chart providing the amounts of various emissions attributable to electricity generation. All such information must be provided to the ICC for inclusion on its Internet site. The GA finds that the benefits of electricity from renewable energy resources and clean-coal technologies accrue to the public at large and encourages energy efficiency to improve the environmental quality and public health of the state. The Department of Commerce and Community Affairs administers the Renewable Energy Resources Program to provide grants, loans, and other incentives to foster investment and the development and use of renewable energy resources. The department shall conduct an annual study and submit a report to the GA including suggestions to encourage the development and use of renewable resources. "Renewable energy resources" does not include hydro power that involves new construction or significant expansion of hydro power dams, nor energy from the incineration of waste wood, tires, garbage, general household and commercial waste, landscape waste, or construction debris. The Renewable Energy Resources Trust Fund is established. Beginning 1/1/98, the following charges shall be imposed and deposited in the trust fund: 5 cents per month on each residential electric account, 5 cents on each residential gas account, 50 cents on each nonresidential electric account taking less than 10 mWs of peak demand, 50 cents on each nonresidential gas account using 4 million therms of gas or less during the previous calendar year, $37.50 per month on each nonresidential electric account using more than 10 mWs, $37.50 per month on each nonresidential gas account taking 4 million or more therms per year. Fifty percent of the money shall be deposited in the trust fund, and the remaining 50 percent shall be deposited in the Coal Technology Development Assistance Fund. Each year beginning 1/1/98, each electric utility and alternative supplier shall annually contribute to the department a pro rata share of $3 million, based on the number of kWhs sold during the preceding year. The funds shall be place in the trust fund to fund projects that promote energy efficiency. (p. 3, 86-87, 241-246)
Maine **H-568** **(LD 1804)**	Renewable resources are defined as total power production capacity not exceeding 100 mW and relying on fuel cells, tidal power, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste generators. Each competitive provider must demonstrate that no less than 30 percent of its portfolio of supply sources is derived from renewable resources. PUC shall review 30 percent requirement and make recommendation for any change to joint standing legislative committee no later than 5 years after beginning of retail competition. PUC shall require utilities to implement energy conservation programs. (p. 15-17)
Massachusetts **H-5117**	The state should ensure energy conservation policies, activities, and services are appropriately funded. Beginning on 3/1/98, and for period of 5 years thereafter, DTE shall require mandatory charge per kWh for all consumers, except those served by municipal lighting plant, to fund energy-efficiency activities, including but not limited to, DSM programs. Charges shall be in following amounts: 3.3 mils per kWh for calendar year 1998, 3.1 mils for 1999, 2.85 mils for 2000, 2.7 mils for 2001, and 2.5 mils for 2002. DTE shall ensure programs are delivered in cost-effective manner utilizing competitive procurement processes. At least 20 percent of amount expended for residential DSM programs for each distribution company in any year, and in no event less than amount funded by charge of 0.25 mils per kWh, which charge shall continue after 2002, shall be spent on comprehensive, low-income residential DSM and education programs. Beginning on March 1, 1998, mandatory per kWh charge for all consumers will be imposed to support development and promotion of renewable energy projects. Charge shall be .00075 mils per kWh in 1998, .001 mils in

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	1999, .00125 mils in 2000, .001 mils in 2001, .00075 mils in 2002, and .0005 mils thereafter. In fiscal year (FY) ending 6/30/01, board of directors of Massachusetts Technology Park Corporation shall review adequacy of moneys generated by mandatory charge. If board determines adjustment is necessary, board shall file recommendations with legislature. Funds shall be deposited in Massachusetts Renewable Energy Trust Fund to generate maximum economic and environmental benefits from renewable energy through series of initiatives that exploit advantages of renewable energy in competitive marketplace. Division of energy resources shall establish renewable energy portfolio standard for all retail suppliers. Every retail supplier must provide minimum percentage of kWhs to end-use customers from renewable energy resources according to following schedule: By December 31, 1999, division shall determine percentage derived from existing renewable generating sources. Thereafter, additional 1 percent of sales by December 31, 2003; additional one-half of 1 percent each year thereafter, until December 31, 2009; and additional 1 percent every year thereafter, until date determined by division. Division shall ensure energy efficiency funds are allocated equitably among customer classes, ensure there will be adequate support for efficiency programs in new construction, remodeling, and replacement of worn out equipment and provide weatherization and efficiency services to low-income customers. Not later than 3/1/99, division shall promulgate regulations to implement foregoing. Within Massachusetts Technology Park Corporation, separate trust fund shall be established known as Massachusetts Renewable Energy Trust Fund. Board may use monies in fund to generate maximum economic and environmental benefits over time from renewable energy to ratepayers by promoting increased availability, use, and affordability of renewable energy and by making operational improvements to existing renewable energy projects. Public interests to be advanced by board's actions shall include development and increased use and affordability of renewable energy resources, protection of environment and health of citizens through prevention, mitigation, and alleviation of adverse pollution effects associated with electric generation, increased fuel and supply diversity, additional employment opportunities through development of renewable technologies, stimulation of increased public and private investment in renewable energy, and stimulation of entrepreneurial activities in these enterprises. Governor shall appoint advisory committee to assist corporation in matters related to fund. Committee shall include not more than 15 individuals. Department of Environmental Protection (DEP) and Attorney General shall promulgate rules and regulations for purpose of preventing, mitigating, or alleviating impacts to resources of state and health of citizens from pollutants emitted by fossil fuel fired generation facilities. Standards for at least 1 pollutant shall be in effect but not before 5/1/03, unless certain other circumstances are met. On or before 1/1/98, each electric company shall file with DTE detailed plan for restructuring. Plan shall include among other things proposed programs and recovery mechanisms to promote energy conservation and DSM. Energy facility siting board is created within DTE but not under control of department. The board shall review need for, costs of, and environmental impacts of transmission lines and certain natural gas facilities. Board shall review environmental impacts of generating facilities consistent with state's policy of allowing market forces to determine need and cost for such facilities. Board has authority to impose civil fines not to exceed $1,000 for each violation for each day with maximum civil penalty not to exceed $200,000. No applicant shall commence construction of generating facility unless approved by siting board. Board shall periodically conduct rulemaking to establish technology performance standards for generating facilities emissions. Municipality or group of municipalities may adopt energy plan that shall define manner in which municipalities implement DSM programs and renewable energy programs. If plan is certified by DTE, municipalities may apply to Massachusetts Technology Park Corporation for monies from Renewable Energy Trust Fund and expend moneys from DSM system benefit charges or line charges. Certain tax deductions are available for use of renewables (see section on "Taxes"). Secretary of Administration and Finance is directed to investigate viability, effectiveness, and cost of requiring all state agencies and facilities to contract for purchase of electricity that includes minimum 10 percent of kWh sales derived from renewables that are available within state. Report shall also project increase in renewable sources likely to be developed as result of this provision, cost to state of procuring new renewable energy from such sources over 10-year period, and benefits to such renewable energy providers of state's preferred purchase policy. Report is to be submitted to legislature and updated each year. Secretary of Administration and Finance shall require any state agency that initiates new construction or substantial renovation to include energy efficiency or renewable technologies. State agencies shall utilize solar- or wind-powered systems when life cycle cost analysis determines that such systems are economically feasible. Each new educational facility that uses more than 1,000 gallons of hot water per day shall be constructed, whenever economically and physically feasible, with solar or renewable energy system as primary energy source. Economic feasibility shall be determined by payback period of not more than 10 years as determined by life cycle cost analysis. DER shall create process for awarding certified renewable energy credits and mechanism for assessing fines and penalties for violations. Division shall also conduct study to determine whether standards for energy efficiency of residential buildings financed by public funds should be implemented and enforced. Office of Environmental Affairs (OEA), DEP and facility siting board shall develop report analyzing environmental benefits accruing pursuant to implementation of generation-performance standards. Study shall explore whether or not department shall promulgate regulations establishing uniform performance standards for any additional pollutants other than previously established standard. (p. 2, 12, 14, 19-21, 24-27, 29, 38-39, 50-54, 108-110, 123-124, 145-146, 149-153)
Montana	Public interest requires continued protection of consumers through funding for public purpose

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S.B. 390	programs for energy conservation, weatherization, and renewable resource projects and applications. Such programs are paid for with universal system benefits charge assessed at meter. Beginning 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for calendar year ending 12/31/95, is minimum annual funding level for total system benefits programs, and 17 percent of that minimum must be used for low-income assistance programs, including weatherization. Balance may be used for other benefit programs such as energy conservation and renewables. Customers with loads greater than 1000 kW pay a system benefit program charge equal to lesser of $500,000, less credits, or .9 mills per kW hour x customer's kWh purchases, less credits. Credits can be carried forward into future years. Customers are entitled to credits for expenditures on renewable energy or conservation-related activities that are part of internal utility programs or activities. Utilities must submit annual summary report to PSC and transition advisory committee detailing activities relating to all system benefit programs. On or before 7/1/02, PSC and transition advisory committee shall reevaluate ongoing need for such programs and make future needs recommendation to legislature. (p. 2-4, 11-12, 16)
New Hampshire **H.B. 1392**	Overall policy goal is to implement restructuring with minimum adverse consequences to environment. Continued environmental protection and long-term environmental sustainability should be encouraged. Nonbypassable, competitively neutral system benefits charge applied to distribution may be used to fund energy efficiency, research and development, and investments in new technologies, as determined by PUC. Increased future commitments to renewables should be consistent with existing state energy policy and be balanced against impact on rates. Over long term, renewables can have significant environmental, economic, and security benefits. Customers should be able to pay premium for renewables. Incentives should be provided for demand side management. (p. 2, 5-7)
Oklahoma **S.B. 500**	
Pennsylvania **H.B. 1509**	
Rhode Island **96-H 8124 Substitute B**	From 1/1/97 until 12/31/01, each distribution company must include 2.3 mils per kWh charge to fund demand side management and renewables. PUC shall determine allocations of funds between two categories. PUC, at its own discretion, may increase sums after notice and public hearing. City where generation plant has been proposed may request builder to fund study of environmental effects of proposed facility, up to lesser of $100,000 or .1 percent of estimated capital cost of project. (p. 43, 52-53)
Virginia **H.B. 1172**	The GA and commission shall implement restructuring with due regard to protection of environment.
Treatment of Transmission and Distribution (T&D)	

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Nevada **A.B. 366**	A public entity does not become subject to provisions of Sections 28-53 solely because entity provides transmission or distribution service to alternative seller except that public entity shall provide such transmission and distribution services on open and nondiscriminatory basis to alternative sellers in accordance with standards PUC may establish by regulation. PUC shall require each provider of noncompetitive service that is necessary to provision of potentially competitive service to make its facilities or services available to all alternative sellers on equal and nondiscriminatory terms and conditions. PUC may establish standards of conduct to prevent anticompetitive activities and such standards of conduct may include limitations on ownership, operation, and control of transmission facilities and any generation necessary to reliable and economic operation of such transmission facilities. PUC shall adopt regulations ensuring that person who owns transmission or distribution facility makes facilities available on equal and nondiscriminatory terms and conditions to all alternative sellers or customers of alternative sellers. Colorado River Commission may sell electricity or provide transmission or distribution service to customers who it was not serving or with whom it did not have contract on effective date of relevant provisions of Act, if Colorado River Commission allows its system for transmission and distribution to be utilized by other alternative sellers pursuant to such terms and conditions as PUC may establish. PUC may conduct investigation of effect on market of transmission congestion or constraints. (Section 40, p. 14; Section 41, p. 15; Section 42, p. 15; Section 44, p. 17; Section 50, p. 20)
Arizona **H.B. 2663**	PPEs shall provide for buy-through service to any electric consumer on request at no additional charge other than charges for required transmission, distribution, or ancillary services from and after 1/1/01. The Act does not alter the existing system of determining distribution system territories through certificates of convenience and necessity, official actions of PPEs, or contracts or agreements among electric distribution utilities. PPEs shall establish unbundled ancillary electric transmission and distribution (T&D) and other service prices and terms and conditions that are nondiscriminatory and that reflect the just and reasonable price for providing the service. PPEs shall adopt reasonable terms and conditions governing the electric distribution utility's obligation to provide electric distribution and other services. PPEs shall allow any provider of electric generation service access to T&D facilities under rates, terms, and conditions that are nondiscriminatory, cost-based, just and reasonable, and comparable to rates charged for the PPE's own use of the same facilities. Every person contemplating construction of transmission lines shall file a 10-year plan with the ACC. The plan shall be reviewed biennially by the ACC, and the ACC shall issue a written decision regarding the adequacy of the existing and planned transmission facilities in the state to meet the present and future energy needs of the state in a reliable manner. (p. 16-17, 19, 37)
California **H.B. 1890**	Continues to be regulated. All customers and suppliers to receive open, nondiscriminatory, and comparable access. (p. 29-30)
Connecticut **Substitute H.B. 5005**	It is in best interests of state to retain regulated distribution system to ensure reliability while allowing competitive generation. All entitlements and obligations from any purchased power contract or independent power producer contract entered into before 7/1/98 by predecessor electric company that are not bought out shall succeed to distribution company. DPUC shall continue to regulate distribution companies. Each distribution company shall maintain integrity of distribution system in conformity with National Electric Safety Code to provide safe and reliable service. Each distribution company shall provide nondiscriminatory access to its distribution facilities to every electric supplier. Each distribution company has obligation to connect all customers to company's distribution system, subject to terms and conditions approved by DPUC. Distribution companies shall continue to provide metering, billing, and collection services. DPUC shall oversee quality and reliability and ensure that they are same as or better than level existing on 7/1/98. In case of new electric transmission line, siting council shall determine whether facility conforms to long-range plan for expansion of electric power grid and whether it will serve interests of electric system economy and reliability. Council will determine if facility is necessary for development of competitive market. (p. 5-7, 10-11, 34-35, 78-79)
Illinois **H.B. 362**	Utilities shall allow aggregation of loads so long as the aggregation meets requirements of any organization responsible for overseeing the integrity and reliability of the transmission system. Charges for delivery services shall be cost based and shall allow the utility to recover the costs of providing delivery services through its charges to delivery service customers that use the facilities and services associated with such costs. Such costs shall include the costs of owning, operating, and maintaining transmission and distribution facilities. Within 180 days of the effective date of the Act, the ICC shall adopt rules and regulations for assessing and assuring the reliability of transmission and delivery systems. The rules shall require each utility or alternative supplier owning, controlling, or operating T&D facilities, subject to the ICC's jurisdiction to adopt and implement procedures for restoring T&D services after outages on a nondiscriminatory basis without regard to whether a customer has chosen the utility, an affiliate, or an alternative supplier. The rules shall require each jurisdictional entity to annually submit to the ICC the number and duration of planned and unplanned outages during the prior year and their impacts on customers, outages that were controllable, and outages that were exacerbated in scope or duration by the condition of facilities, equipment, or premises, service interruptions due solely to the actions or inactions of alternative suppliers, a detailed report of the age, current condition, reliability, and performance of the entity's existing T&D facilities. Every 3 years,

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	the ICC shall assess the annual report of each entity and evaluate its reliability performance. (p. 6, 14-15, 18, 56, 75-77)
Maine H-568 (LD 1804)	Upon request from competitive provider, PUC shall provide load data on class basis that is in possession of T&D utility, subject to reasonable protective orders to protect confidentiality. Except as otherwise permitted, on or after 3/1/00, IOU T&D may not own, have financial interest in, or otherwise control generation or generation-related assets. After commencement of retail access, large investor-owned T&D utility serving more than 50,000 retail customers may not sell electricity to any retail customer. Affiliated provider may sell to retail customers outside service territory of distribution utility with which it is affiliated and within service territory of distribution utility with which it is affiliated, except that affiliate may not sell more than 33 percent of total kWh sold within service territory of distribution utility. No later than 1/1/05, based on its evaluation of development of competitive retail sales market, PUC shall complete evaluation of need for market share limitation and shall report its findings to legislature. Distribution utility may not engage in joint advertising or marketing programs of any sort with its affiliated competitive provider. Employees of distribution utility may not be shared with and must be physically separated from those of affiliated competitive provider. Distribution utility and its affiliated competitive provider must keep separate books and records. All regulated products and services offered by distribution utility, including any discount, rebate, or fee waiver, must be available to all customers and competitive providers simultaneously and without undue or unreasonable discrimination. (p. 3, 8-12)
Massachusetts H-5117	The state should enter into compacts with other New England states and New York state to protect reliability of interconnected regional transmission and distributions systems. Transmission companies shall provide transmission to all generation companies, municipal lighting plants, suppliers, and load aggregators whether affiliated or not on comparable, nondiscriminatory prices and terms. Newly created distribution companies shall be prohibited from directly owning, operating, or controlling transmission facilities. Municipality, upon 60 days' notice to electric company and to DTE, may convert its street lighting service from tariff to alternative tariff approved by DTE providing for delivery service by electric company over distribution facilities and wired owned by electric company to lighting equipment owned or leased by municipality. No sooner than 1/1/00, DTE shall commence study to determine whether metering, meter maintenance and testing, customer billing, and information services provided by distribution companies since 3/1/98 should be unbundled and provided through competitive market and to review creation of exclusive distribution territories to determine if such exclusivity should be terminated or altered. If DTE determines services should be subject to unbundling and competition or territorial exclusivity should be terminated or altered, DTE shall no later than 1/1/01 file its recommendations with legislature. (p. 3, 49, 52-53, 55, 99, 142)
Montana S.B. 390	Distribution services providers must make distribution facilities available to all suppliers, providers, and customers on nondiscriminatory, comparable basis; and be emergency supplier of electricity and related services. When distribution services provider acts as emergency supplier, supplier that should have provided power must reimburse distribution company according to prescribed formula. Distribution services providers are not required to purchase reserve supply to fulfill emergency obligations. Transmission services must also be available on nondiscriminatory, comparable basis. If co-op offers electricity competitively to customers using utility's distribution facilities, co-op must create affiliated for-profit entity to serve those customers that allows entity to be taxed at same level as other for-profit suppliers. PSC shall regulate retail transmission and distribution services including establishment of just and reasonable rates, which may include performance-based rates. (p. 2, 6, 9-10, 12-13, 22)
New Hampshire H.B. 1392	T&D should remain regulated for foreseeable future. PUC to take necessary measures to ensure nondiscriminatory, comparable, and open access to T&D. (p. 4-5)
Oklahoma S.B. 500	A primary goal of restructured industry is to enable suppliers to engage in fair and equitable competition through open, equal, and comparable access to T&D systems. Entities which own both T&D as well as generation facilities shall not be allowed to use any monopoly position in these services as barrier to competition. Generation shall be functionally separated from T&D services, which shall remain regulated. Comparable access for retail suppliers competing with affiliates of entities supplying T&D shall be assured. Commission shall monitor companies providing T&D and take necessary measures to ensure no supplier of such services has unfair advantage in offering and pricing such services. Benefits associated with implementing independent system planning committee composed of owners of electric distribution systems to develop and maintain planning and reliability criteria for distribution facilities shall be evaluated. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect, as well as rates for regulated services. Final report shall be provided to legislative task force no later than 8/31/00. (p. 3-7)
Pennsylvania H.B. 1509	Continues to be regulated as natural monopoly. Distribution company remains provider of last resort unless PUC approves alternative. PUC shall require all transmission and distribution facilities to provide comparable open access to all customers and suppliers. There is rebuttable presumption distribution company can accommodate all requests for service from suppliers but does not have to install

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	nonstandard equipment unless customer pays full cost of such facilities. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. Company must accept returning customer on same terms and conditions as new applicant. Distribution company shall implement procedures to require suppliers to deliver sufficient power to meet supplier's customer obligations. Subject to PUC approval, company may require customer to pay for enhanced metering capability. (p. 22, 28, 34, 46, 48-49)
Rhode Island **96-H 8124 Substitute B**	T&D companies must provide nondiscriminatory access on reasonable terms consistently applied to all customers. Distribution companies must terminate all requirements contracts with generators no later than 3 months after 40 percent of kWh sales in New England are available for retail access and can only own or operate generation or transmission facilities through affiliates, with some specific exceptions. (p. 6, 17-19, 21)
Virginia **H.B. 1172**	
Legislative Oversight	
Nevada **A.B. 366**	PUC shall issue quarterly report to legislature assessing developments in electric industry in Nevada. Report shall evaluate, at minimum, effectiveness of competition, compatibility of direct access with environmental goals, impacts of competition on each customer class relative to present structure, and opportunities to cooperate with other states or Federal Government in implementation of competition. In quarterly report for first quarter of 1999, PUC shall provide comprehensive evaluation of development of markets for potentially competitive services since 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 53, p. 23; Section 335, p. 148; Section 336, p. 148)
Arizona **H.B. 2663**	The exclusion of cities and towns with a population of 75,000 or greater from mandatory participation in retail competition and the retention of exclusive service territories by electric distribution service territories are subject to legislative review in 08. Each PPE shall report its beginning effective date for bundled service price reductions to the joint legislative budget committee by 12/31/98. The provisions regarding supplier of last resort are subject to legislative review by the auditor general in 08. The review shall include recommendations on whether distribution utilities shall remain the provider of last resort or if other suppliers should bid to be the provider of last resort. The provisions requiring electric distribution utilities to provide other services such as billing and collection, metering, and meter reading are subject to sunset review by the auditor general in 03. A joint legislative study committee on electric deregulation is established consisting of 3 members of the Senate and 3 from the House. Specific areas are outlined for the study. Additionally, the legislature intends to determine the long-range effect of the act by assembling, in 08, a commission of legislators, government officials, industry representatives, and private citizens, selected by the president of the Senate, speaker of the House, and the Governor, to analyze the benefits and burdens of electric power competition in the state. The ACC shall inform the legislature and testify before the joint legislative study committee if the ACC delays the 12/31/98 or 12/31/00 dates for competition. The joint legislative study committee expires 12/31/00. (p. 17, 19, 21, 35, 43-45)
California **H.B. 1890**	Five-member oversight board composed of three gubernatorial appointees, one Senator, and one Assemblyman. Board oversees ISO and Power Exchange and serves as appeal board from ISO decisions. (p. 5, 34-36)
Connecticut **Substitute H.B. 5005**	Not later than 12/1/98, DPUC shall submit report to GA outlining scope of education outreach program. On or before 1/31/01, and annually thereafter until 1/31/06, Energy Conservation Management Board shall provide report documenting expenditures, fund balances, and cost effectiveness of conservation and load-management programs. Speaker of House, president pro tem of Senate, majority leader of House, majority leader of Senate, minority leader of House, and minority leader of Senate shall appoint specified individuals to Renewable Energy Investments Advisory Committee. Advisory committee shall annually issue report reviewing activities of fund and provide copy to GA. Not later than 1/1/99, DPUC shall submit findings regarding exit fee charged to customers who have installed self-generation facilities. Not later than 1/1/99, DPUC shall report findings to GA regarding standards and procedures to facilitate aggregation of end-use customers. Not later than 1/1/99, Energy Advisory Board shall report findings and recommendations regarding whether metering, billing, and collection services by distribution companies would be more efficiently handled if such services were performed by electric suppliers. Not later than 1/1/02, DPUC and CC shall report findings and recommendations to GA regarding how best to structure program for providing electric services to customers who do not or are unable to arrange for or maintain electric generation services. Not later than 1/1/03, DPUC and CC shall make recommendations to GA regarding difference between average rate paid under standard offer and average rate paid by all

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	other customers. DPUC in consultation with CC shall monitor state of competition and average total rates for each customer class and, not later than 1/1/02 and annually thereafter, shall report findings. Not later than 1/1/00, and annually thereafter, DPUC shall report information relating to average interruption duration index and average interruption frequency index. Not later than 1/1/00, and annually thereafter, Department of Environmental Protection in consultation with DPUC shall report statewide data for total megawatt hours produced, total megawatt hours purchased, proportion of production derived from various specified fuels, and amount of emissions. Not later than 1/1/99, and annually thereafter until 1/1/05, DPUC shall report number of dislocated workers who have lost their jobs as result of restructuring. Not later than 1/1/99, and annually thereafter, DPUC shall report number of applicants licensed as suppliers. After consultation with CC, Office of Policy and Management and Attorney General, DPUC shall report to GA, not later than 1/1/00, findings regarding appropriateness of performance-based regulation as opposed to traditional cost-plus regulation. (p. 36, 54, 71, 95-101)
Illinois **H.B. 362**	The ICC shall annually review and report the progress, participation, and effects of billing experiments to the GA. On or before 12/31/99, and once every 3 years thereafter, the ICC shall monitor and analyze patterns of entry and exit, applications for entry and exit, and any barriers to entry or participation that may exist for services. The ICC shall analyze any impediments to establishment of a fully competitive energy and power market and shall include findings, together with recommendations, for legislative action in a report to the GA. Beginning in 01 and ending in 06, ICC shall prepare an annual report regarding the development of electricity markets in the state, which shall be filed with the GA by 4/1 of each year. Such reports shall include at a minimum the following information: aggregate annual peak demand of retail customers in the preceding year; total annual kWhs delivered and sold to retail customers in the state by each utility, within its own service territory and outside its own territory, and by each alternative supplier; the percentage of total kWhs delivered and sold to retail customers in state in the preceding calendar year by each utility within its service territory and outside its service territory, and each alternative supplier; and any other information the ICC considers significant. Additionally, each electric utility shall file with ICC, on or before 5/15 of each year 99 through 06, a report on the following topics, which shall, in turn be reported to the GA: data on each customer class in which delivery services have been elected, including number of retail customers in each class, kWhs consumed, revenue loss experienced, total amount of funds collected from each class and such other information as ICC may require. The utilities must also describe any steps taken to mitigate and reduce costs including a detailed description of steps during the preceding calendar year and a summary of steps taken since the effective date of the Act. The report shall include the annual savings or additional charges realized by customers, a summary of the utility's transitional funding instruments, kWhs consumed by customer class multiplied by the revenue per kWh, adjusted to remove certain charges, the utility's total revenue and net income for each calendar year beginning with 97, any consideration in excess of the net book cost received by the utility from a sale of generating plants, any consideration received by the utility from sales or transfers. The ICC shall report to the GA no later than 12/31/02 on performance-based rate programs. The department shall conduct an annual study on the use and availability of renewable energy resources and shall submit a report on the study to the GA. If as of 12/31/02 the existing energy assistance program has not been replaced by a new one, the GA shall review the program. On or before 12/31/03, the department shall prepare a report for the GA on the expenditure of funds from the low-income energy assistance block grant fund. An Energy Assistance Program Design Group is established to design a low-income energy assistance program for the period beginning 1/1/03. The group shall be established by the GA or a joint committee thereof. The group shall provide a report with recommendations to the GA on or before 1/1/02. The report must include recommendations defining an eligible low-income residential customer, recommendations regarding the continuation of the program, recommendations ensuring low-income residential customers have access to essential energy services, recommendations addressing past due amounts owned to utilities by low-income individuals, demographic and other information necessary to determine total number of customers eligible for assistance, recommendations to encourage conservation, efficiency, and responsibility among low-income customers, any recommended changes to existing legislation and an estimate of the cost of implementing the recommendations. (p. 16-17, 71-73, 90-94, 170, 242, 254-256)
Maine **H-568** **(LD 1804)**	On December 31 of each calendar year, PUC shall submit to joint standing legislative committee report describing PUC's activities in carrying out requirements of Act, and include draft legislation designed to modify Act consistent with public interest. Joint standing legislative committee having jurisdiction over utility and energy matters may report out legislation concerning electric energy restructuring to future legislative sessions. (p. 22, 26)
Massachusetts **H-5117**	The DTE is under supervision and control of 5-member commission appointed by Governor. Commission shall make annual report of its activities in January of each year to General Court. Beginning on 3/1/98, and for 5 years thereafter, mandatory per kWh charge for all customers shall be imposed to fund energy efficiency activities. On 3/1/01, DER shall determine if energy investments should be continued and, if so, shall file with General Court recommendations to extend charge for time certain. In FY ending 6/30/01, directors of Massachusetts Technology Park Corporation shall review adequacy of monies generated by mandatory charge. If adjustment in charge is necessary,

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	board shall file recommendations with GA. On or before 1/1/02, board shall submit to legislature report reviewing activities and expenditures of Massachusetts Renewable Energy Trust Fund along with proposed activities and funding levels for succeeding 5 years for review and approval by legislature. DTE consumer education plan shall be submitted to legislature and shall recommend provision of services funded by state only to extent private market cannot or does not adequately meet information needs of retail customers. DER shall annually issue report containing information on all issues relating to reliability and specify information on price, service, and competitiveness. Massachusetts Technology Park Corporation and advisory committee shall annually submit, to Governor and legislature, report dealing with expenditure and investment of monies from fund. Reporting shall begin with FY ending 6/30/99, and shall be filed by 8/15 of each year. DTE shall file biannual report including nature of consumer complaints, number of consumer claims, and resolution of consumer claims. Not later than 3/1/99, DTE shall conduct and investigation and report to legislature regarding cost and benefits of expanding eligibility for low-income discount rates. DTE shall make recommendations relative to continuation of low-income discount rate. DTE shall track all unauthorized customer switches during calendar year. Beginning in 1999, DTE, by 3/31, shall file annual report with legislature detailing total number of unauthorized switches, enforcement procedures, total amount of dollars returned to customers, total amount of dollars collected in civil penalties, and overall impact of anti-switching provisions. DTE shall notify legislature within 1 business day upon approval and initiation of transition charge for electric company. DTE and siting board shall file report by 3/1 of each year detailing substance of all plans and forecasts concerning need for and cost of and environmental impacts of transmission lines and other facilities, along with analysis of reliability and diversity of electric power and gas needs. No sooner than 1/1/00, DTE shall commence investigation of metering, meter maintenance, customer billing, and information services provided by distribution companies since 3/1/98. The study shall analyze and determine whether such services should be unbundled and provided through competitive market. Study shall also investigate whether exclusive distribution territories should be terminated or altered. If DTE determines such services should be subject to unbundling or territorial exclusivity should be terminated or altered, it shall, no later than 1/1/00, file its recommendations. Any unbundling and creation of retail competition of such services shall not commence unless statutorily allowed. Not later than 1/1/00, Department of Revenue shall study various tax issues related to restructuring, including alleviating any undue fiscal hardship suffered by cities and towns as result of reduced property tax revenues. Department shall, by 5/1/01, file its recommendations and findings. Within 30 days after passage of act, Department of Revenue shall study potential fiscal implications of proposed amendments to state tax code contained in act. Department shall file report with legislature. DTE and DER shall submit any rules and regulations promulgated under Act to legislature for review at least 30 days prior to effective date of regulations. Secretary of Administration and Finance shall conduct study concerning viability, effectiveness, and cost of requiring all state agencies to enter into certain contracts for purchase of renewable energy. Report is to be submitted to legislature by 3/1/00 and updated annually thereafter. DER shall file annual report detailing compliance of all state agencies with provisions requiring construction of new facilities to utilize energy efficiency, water conservation, and other renewable energy technologies as specified in Act. DTE shall conduct study to determine to what extent renewable portfolio standards create process for awarding certified renewable credits to generators and suppliers. Division shall also create mechanism for assessing fines and penalties for violations and shall report its recommendations including draft legislation. DTE shall study whether standards for energy efficiency of residential buildings financed by state should be implemented and enforced. Division shall file report including its recommendations by 3/1/01. OEA, DEP, energy facilities siting board shall develop report to analyze environmental benefits accruing pursuant to generation performance standards. Study shall explore whether or not department shall promulgate regulations to establish uniform performance standards for any additional pollutants. Report shall include proposed legislation designed to implement recommendations. Act creates special commission on deregulation and convergence of industry to study ramifications of past and future efforts to restructure major, regulated businesses and industries, including but not limited to electric utility industry. Commission shall study and make recommendations on potential convergence of industries in merged or joint projects and future regulatory role of state over these industries. Commission shall issue initial report to legislature on or before 7/1/99. (p. 8, 12-14, 18-19, 30, 63, 66, 74, 84, 109, 142-146, 149-153, 154-155)
Montana **S.B. 390**	Transition advisory committee consists of 8 voting members, equally balanced by party: 4 appointed by Speaker and 4 appointed by Senate President. Non-voting advisory members include: director of dept. of environmental quality; 1 public utilities appointee; and 1 representative each from consumers, cooperatives, and PSC. Governor appoints 1 each non-voting member from: industry, non-industrial consumers, organized labor, environmental/ conservation, low-income program provider, Indian tribes, power market industry. PSC, legislative counsel, and agencies provide staff. Committee meets quarterly and dissolves on earlier of date full transition is completed or 12/31/04 and shall: provide annual report on or before 11/1/01 to governor, speaker, Senate president, and PSC; provide quarterly reports to legislature thru 1/1/99; analyze and report on transition to effective competition. Annual report in 2000 must evaluate pilot programs with loads under 1000 kWh and include legislative recommendations about best means to further encourage choice, market access, and need for additional consumer protection revisions. Criteria for evaluating effective competition are specified. On or before 7/1/02, committee and PSC shall reevaluate need for ongoing universal system benefits programs and make recommendations. On or before 11/1/01, committee shall determine whether Montana utilities have opportunity to market outside state comparable to reverse.

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	On or before 11/1/98, committee shall make recommendations to governor and legislature regarding low-income assistance programs. (p. 4, 12, 15-16, 27)
New Hampshire **H.B. 1392**	Establishes 14-member legislative oversight committee, seven from each house, with 2-year terms. Committee to report annually on or before 11/1 to governor, legislature, and PUC. In conjunction with PUC, report shall address new legislation and proposed amendments to existing law to promote restructuring. (p. 12)
Oklahoma **S.B. 500**	Act creates Joint Electric Utility Task Force composed of 14 members of legislature, 7 each selected by Senate president and House speaker. Task force may appoint advisory councils made up of representatives of interested parties. Task force shall direct and oversee studies by Commission and Tax Commission. Task force shall remain in effect until termination, which shall be no later than 1/1/03. Commission shall make reports to task force on independent system operator issues, technical issues, financial issues, and consumer issues no later than 2/1/98, 12/31/98, 12/31/99, and 8/31/00, respectively. Task force may make final recommendations to governor and legislature. Task force is authorized to retain consultants and experts to study creation of ISO and benefits of establishing power exchange, which would operate as power pool. All studies and recommendations relating to ISO shall be submitted to task force on or before 2/1/98, and shall conform to FERC Order No. 888. (p. 8-9)
Pennsylvania **H.B. 1509**	
Rhode Island **96-H 8124 Substitute B**	On 1/1/98, and annually for next 4 years, PUC to file report with governor and legislature detailing developments in competitive supply market, estimated savings from retail competition, progress towards regional transmission agreement, reforms instituted by regional power pool, and status of restructuring in surrounding states. (p. 23)
Virginia **H.B. 1172**	
Taxes	
Nevada **A.B. 366**	If two or more persons perform separate functions collectively needed to supply electricity to final customer and property would be centrally assessed if owned by one person, it shall be centrally valued and apportioned. Proportion of tax levied by each county shall be determined according to valuation of contribution of each person to aggregate valuation of property. However, this provision does not apply to QFs built before 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 278, p. 114-116; Section 335, p. 148)
Arizona **H.B. 2663**	As a condition of obtaining a certificate, an electric supplier shall agree to be subject to the transaction privilege taxes and affiliated excise taxes. Regulation of suppliers providing generation services is a matter of statewide concern. Cities, towns, and counties shall not require franchises for suppliers to provide electric generation service within their jurisdiction and shall not impose rents, charges, or taxes for the use of public rights of way for provision of generation service, except a fee equal to the franchise fee of the distribution utility maybe charged to the supplier on any portion of a retail electricity sale not otherwise subject to a franchise fee made using electric distribution facilities that are franchised as of the effective date of the Act. Nothing in the Act affects the authority of cities, towns, and counties to require franchises for electricity suppliers providing electric distribution service within their jurisdiction. Certain adjustments are made to the existing tax code. Provision is made for certain counties to impose a general use tax on each retail customer consuming electricity in the county. (p. 36, 38, 41-42)
California **H.B. 1890**	
Connecticut **Substitute H.B. 5005**	On and after 7/1/98, there is credit allowed against tax imposed under Chapter 208 of *General Statutes* on electric suppliers with respect to each displaced worker hired by electric supplier. Amount of credit is $1,500 for each displaced worker. Displaced worker is any Connecticut employee, other than officer or director, of electric company terminated as direct result of restructuring in electric industry. For period of 10 years, beginning with assessment year during which value of electric generation facility decreases as direct result of restructuring, but in no event later than 10/1/05, municipality in which facility is located will be entitled to, in addition to amount of tax that generation facility is otherwise liable for under Chapter 203, to amount computed by specified formula. Amount shall be percentage of: (1) difference between value of generation facility as it would have been assessed but for restructuring, taking into account depreciation and assessed value of facility; (2) multiplied by mil rate of municipality in which facility is located; and (3) minus amount of any increase in property tax revenues to municipality as result of any increase in value of facility or additional generation facility in municipality. Each distribution company providing transmission services shall pay quarterly tax upon its gross earnings in each calendar quarter at rate of:

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	(a) 8.5 percent of its gross earnings from providing transmission services or distribution services to other than residential service customers; and (b) 6.8 percent of such gross earnings from providing transmission services or distribution services to residential service. Any municipality may, upon approval by its legislative body, abate property taxes due for any tax year with respect to any property of electric cooperative. (p. 72-73, 84, 99-100)
Illinois **H.B. 362**	A muni system may elect to allow existing or future customers to have access to alternative suppliers or may elect to become an alternative supplier itself. However, at no time shall a muni system make such an election if the election places at risk any tax-exempt status under federal or state tax statutes. The GA finds that restructuring renders the existing taxation system impracticable and infeasible. The existing system must be changed to preserve revenue neutrality and to avoid placing any supplier at a competitive disadvantage as well as to minimize additional administrative costs and to avoid the imposition of increased tax burdens on consumers, particularly residential consumers. In place of the existing tax, an electricity excise tax is imposed on the privilege of electric use measured by the kWhs delivered to the purchaser. Collections shall substantially equal the amount of revenue previously collected. Certain nonresidential consumers of electricity may register with the Department of Revenue as self-assessing purchasers and pay the tax directly to the department at a rate established as a percentage of such consumer's purchase price for electricity distributed, supplied, furnished, sold, transmitted, or delivered to the purchaser. A tax is imposed on the privilege of using electricity in the state for consumption and not for resale at the following rates per kWh delivered to the purchaser: first 2,000 kW, 0.330 cents/kWh; next 48,000 kWh, 0.319; next 50,000 kWh, 0.303; next 400,000, 0.297; next 500,000, 0.286; next 2 million, 0.270; next 2 million, 0.254; all electricity in excess of 20 million kWhs in a month, 0.202. The tax imposed on self-assessing purchasers is 5.1 percent of the purchase price for all electricity furnished to the self-assessing purchaser in a month. Special rules apply to sales by munis and co-ops. There is an exemption for multi-state taxation. The tax shall be collected from the purchaser by the delivering supplier , except in the case of a self-assessing purchaser. A self-assessing purchaser may not revoke the election to become a self-assessing purchaser for at least 12 months. The existing invested capital tax on electric utilities is replaced with a new tax based on the quantity of electricity delivered in the state. A privilege tax is imposed on the annual gross revenue of each public utility to cover the expense of administering the Act. Municipalities are authorized to impose taxes on the privilege of using or consuming electricity. Specific rates are established in the Act. Municipalities are entitled to require a franchise contract from an electricity deliverer as a condition of allowing the deliverer to use any portion of any public right of way within the municipality. A municipal electricity infrastructure maintenance fee is authorized with rates specified in the Act. Existing agreements between deliverers and municipalities for the use of public rights of way remain valid. However, any municipality receiving payments under such contracts waives the right to receive an infrastructure maintenance fee as provided in the Act. (p. 41-42, 94-97, 175-240)
Maine **H-568** **(LD 1804)**	On or before 1/1/98, PUC and state planning office shall provide legislature with recommendations concerning funds to assist low-income consumers through general fund appropriations or through tax on all energy sources in state. (p. 26)
Massachusetts **H-5117**	An electric company authorized to recover transition cost amounts that currently has no binding agreement for tax payments or payments in lieu of taxes to municipalities in which company's generation facilities are located shall be required to make transition payments to any municipality in which affiliated generation facility is located and has been devalued for property tax payment purposes. However, where such binding agreement has been entered into on or after effective date of Act, such agreement shall govern, and generation facility shall be exempt from provisions of Act regarding transition payments to municipalities. Payments under agreement shall offset any reductions of property taxes as result of any devaluation of generating facility. Section does not provide for exemption from property tax and is in addition to such tax obligation. For FY '01, such amount shall be equivalent to 90 percent of difference between local property tax value of property as of 1/1/96 and fair cash value of property as of 1/1/00, multiplied by applicable commercial tax rate for FY '01. For each FY through '09, calculated amount is adjusted. In FY '09, percentage is 10 percent of difference between local property tax value as of 1/1/96 and fair cash value of property as of 1/1/08, multiplied by applicable commercial tax rate for FY '09. City or town is authorized to enter into agreement with New England Power Company concerning assessed valuation of all real and personal property presently owned by company in town for FY '97 to FY '01 provided, however, agreement shall constitute good faith attempt to value property at its fair market value. Special rules are enacted for nuclear power generation facilities. Not later than 1/1/02, Department of Revenue shall commence investigation and study regarding payments in lieu of tax payments. Study shall also investigate alleviating any undue fiscal hardship suffered by cities and towns as result of reduced property tax revenues from either devaluation of property containing generation facilities, or sale of such facilities and subsequent termination of their use. Department of Revenue shall within 30 days of effective date of Act commence investigation of potential fiscal implications of 2 proposed amendments to tax code. Amendments would allow individual who contracts with supplier to purchase renewable electricity in excess of minimum requirements to take income tax deduction equivalent to 50 percent of above-market price. Amendment would also allow individual purchasing such electricity to qualify for income tax deduction equivalent to 20 percent of cost, up to maximum

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	of $10,000 annually. Furthermore, any business contracting with supplier to purchase renewable energy in excess of minimum requirements under portfolio standard would be entitled to business tax deduction equivalent to 25 percent of above-market price. Such business would also be entitled to income tax deduction equivalent to 10 percent of cost, up to maximum of $50,000 annually. (p. 31-34, 144-146)
Montana **S.B. 390**	During 4-year transition period, utilities may accelerate amortization of accumulated deferred investment tax credits associated with T&D and general plant if earnings fall below 9.5 percent earned return on average equity. Revenue oversight committee shall analyze state and local tax revenue derived from previously regulated electricity suppliers that will enter competitive market and report to legislature annually on how revenue to state and local government is changed by restructuring and competition. On or before 11/30/98, revenue oversight committee shall recommend legislative changes, if any, to address comparable state and local taxation burdens on all market participants. (p. 8, 10, 16, 21-22)
New Hampshire **H.B. 1392**	
Oklahoma **S.B. 500**	The Tax Commission shall study and fully assess impact of restructuring on state tax revenues and all other facets of current utility tax structure both on state and all other political subdivisions. Study shall include feasibility of uniform consumption tax or other method of taxation. Tax Commission is expressly prohibited from promulgating any rule or order without prior express authorization from legislature or legislative task force. In event uniform tax policy, which allows all competitors to be taxed on fair and equal basis, has not been established on or before 7/1/02, effective date for customer choice shall be extended until such time as uniform tax policy has been established. (p. 8)
Pennsylvania **H.B. 1509**	Restructuring to be accomplished in revenue neutral manner at level necessary to recoup losses that may result form restructuring. (p. 57-66)
Rhode Island **96-H 8124 Substitute B**	By 1/1/97, retail electric licensing committee shall submit plan to legislature for taxing and/or assessing distribution and transmission companies and nonregulated power producers. (p. 22)
Virginia **H.B. 1172**	In implementing restructuring, GA shall give due regard to unique regulatory and taxation structures of all electric utilities and power supply cooperatives in state.
Performance Based Rates (PBR)	
Nevada **A.B. 366**	PUC shall adopt regulations permitting innovative methods of pricing noncompetitive services upon finding that such methods would improve performance or lower costs. (Section 44, p. 17)
Arizona **H.B. 2663**	
California **H.B. 1890**	
Connecticut **Substitute H.B. 5005**	The DPUC shall promptly undertake investigation of new pricing principles and rate structures. For purposes of investigation and report to GA, DPUC shall design or cause each company to design plan for performance-based regulation of each electric distribution company that encourages such companies to control their costs while they continue to provide efficient, safe, and reliable distribution services. Designing such plan, DPUC or company shall identify those performance standards that would be appropriate for performance-based regulation and analysis of how such plan should best be structured so that companies would have flexibility in implementing such plan. DPUC shall also determine whether performance-based regulation would better meet goal of reducing costs to all customer classes than traditional cost-plus regulation. (p. 80-81, 94-95)
Illinois **H.B. 362**	The ICC is authorized to approve applications from utilities to implement alternatives to rate of return regulation and to substitute a regulatory mechanism that rewards or penalizes the utility through adjustment of rates based on utility performance. The programs may consist of alternatives, including earnings sharing, rate moratoria, price caps, or flexible rate options. The ICC shall approve the program if it finds the program is likely to result in lower rates than would have been in effect under traditional rate of return regulation, the program is likely to result in other substantial and identifiable benefits that would be realized by customers, the program is not likely to adversely affect service reliability, implementation is not likely to result in deterioration of the utility's financial condition or adversely affect development of competitive markets. The program must include annual reporting that will enable the ICC to adequately monitor its implementation and must include equitable sharing of any net economic benefits between the utility and its customers. ICC shall open a proceeding to review any such program 2 years after implementation to determine whether the

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	program is meeting its objectives. The ICC must determine whether implementation is in the public interest, whether it will produce fair, just, and reasonable rates, and must specifically identify how the departure from traditional rate of return rate making will benefit rate payers through efficiency gains, cost savings, or improvements in productivity. Such programs shall not extend beyond the utility's service territory and shall not extend beyond 6/30/00. No later than 12/31/00, ICC shall report to the GA with appropriate legislative recommendations. (p. 28, 166-170)
Maine **H-568** **(LD 1804)**	
Massachusetts **H-5117**	The DTE is authorized to promulgate rules and regulations to establish and require performance-based rates for each distribution, transmission, and gas company. In complying with service quality standards and employee benchmarks established by act, distribution, transmission or gas company that makes performance-based rate filing after effective date of act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on 11/1/97, unless part of collective bargaining agreement or with approval of DTE following evidentiary hearing. (p. 62)
Montana **S.B. 390**	PSC shall establish just and reasonable rates, through established rate making principles, for distribution and transmission services and shall regulate these services. PSC may approve performance-based rate making on demonstration by utilities that alternative methods comply with utilities' transition plans. (p. 13)
New Hampshire **H.B. 1392**	Performance-based or incentive regulation should be considered for transmission and distribution services. (p. 4)
Oklahoma **S.B. 500**	
Pennsylvania **H.B. 1509**	PUC has authority to approve flexible rates, including negotiated, contract-based tariffs and to use performance based rates. (p. 45)
Rhode Island **96-H 8124 Substitute B**	It is in public interest to establish performance based rate making. To hold overall rate increases to level of inflation, for period 1/1/97 to 12/31/98, distribution companies shall implement PBR plan in accordance with specified provisions, subject to PUC approval. However, rates for low-income customers cannot increase. (p. 3, 33-35)
Virginia **H.B. 1172**	

Additional Comments: Please note that several states, i.e., California (S.B. 477/1997) and Rhode Island (97-H 7003), subsequently enacted additional legislation that supplemented and/or amended the measures discussed in this table. Concurrently with the passage of H.B. 362, which is summarized above, Illinois passed two additional bills (H.B. 56 and H.B. 1817) that are not condensed herein. Finally, several states are proceeding with electric industry restructuring through commission proceedings rather than legislatively. Arizona is unique; both its legislature and commission have ordered programs.

Compiled by Research Division of Nevada's Legislative Counsel Bureau
Utilities: State Matrix 7-98

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Sponsor	
H.R. 338 - Stearns	Rep. Cliff Stearns (R-FL)
H.R. 655 - Schaefer	Rep. Dan Schaefer (R-CO)
H.R. 1230 - DeLay	Rep. Tom DeLay (R-TX)
H.R. 1359 - DeFazio	Rep. Pete DeFazio (D-OR)
H.R. 1960 - Markey	Rep. Ed Markey (D-MA)
H. R. 2909 - Pallone	Rep. Frank Pallone (D-NJ)
H. R. 3927 - English	Rep. Phil English (R-PA)
H. R. 3976 - Tauzin	Rep. W. J. Tauzin (R-LA)
H.R. 4183 - Solomon	Rep. Gerald Solomon (R-NY)
S. 237 - Bumpers	Sen. Dale Bumpers (D-AR)
S. 1401 - Bumpers/Gorton	Sen. Dale Bumpers (D-AR) / Sen. Slade Gorton (R-WA)
S. 621 - D'Amato	Sen. Alfonse D'Amato (R-NY)
S. 687 - Jeffords	Sen. Jim Jeffords (R-VT)
S. 722 - Thomas	Sen. Craig Thomas (R-WY)
S. 1276 - Bingaman	Sen. Jeff Bingaman (D-NM)
S. 1483 - Murkowski	Sen. Frank Murkowski (R-AK)
S. 2182 - Gorton	Sen. Slade Gorton (R-WA)
S. 2187 - Nickles	Sen. Don Nickles (R-OK)
S. 2287 [Clinton]	Sen. Frank Murkowski (R-AK) [Introduced on behalf of the Clinton Administration.]
Type of Bill	
H.R. 338 - Stearns	Limited (i.e., repeals Section 210 of PURPA).
H.R. 655 - Schaefer	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).
H.R. 1230 - DeLay	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
H.R. 1359 - DeFazio	Limited (i.e., addresses only conservation, efficiency, renewable energy, and universal service).
H.R. 1960 - Markey	Comprehensive (i.e., retail access, PUHCA and PURPA exemption).
H. R. 2909 - Pallone	Limited (i.e., addresses environmental costs of generation)
H. R. 3927 - English	Limited (restricts the use of tax-exempt financing by governmentally owned utilities).
H. R. 3976 - Tauzin	Limited. Repeals PUHCA.
H.R. 4183 - Solomon	Limited (amends PURPA).
S. 237 - Bumpers	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
S. 1401 - Bumpers/Gorton	Comprehensive (i.e., retail access, PUHCA repeal, partial PURPA repeal).
S. 621 - D'Amato	Limited. Repeals PUHCA.
S. 687 - Jeffords	Limited (i.e., addresses only conservation, efficiency, renewable energy, and universal service). Repeals portions of Section 210 of PURPA.
S. 722 - Thomas	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).
S. 1276 - Bingaman	Limited (i.e., does not mandate retail competition, but gives states authority to order it; requires FERC to establish and enforce national electric reliability standards).
S. 1483 - Murkowski	Limited (i.e., addresses only tax-exempt bond financing of public power entities).
S. 2182 - Gorton	Limited (addresses tax-exempt status of government-owned utilities).
S. 2187 - Nickles	Limited (prohibits states from granting exclusive rights to sell electric energy).
S. 2287 [Clinton]	Comprehensive (i.e., retail access, PUHCA repeal and PURPA reform).
"Date Certain"	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	December 15, 2000.
H.R. 1230 - DeLay	January 1, 1998.
H.R. 1359 - DeFazio	

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H.R. 1960 - Markey	
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	December 15, 2003.
S. 1401 - Bumpers/Gorton	January 1, 2002.
S. 621 - D'Amato	Not later than 18 months after enactment.
S. 687 - Jeffords	
S. 722 - Thomas	
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	January 1, 2002.
S. 2287 [Clinton]	January 1, 2003 (states may opt out of retail competition).
Retail Access Implementation	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	State directed.
H.R. 1230 - DeLay	FERC directed.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	State or utility directed.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	State or utility directed.
S. 1401 - Bumpers/Gorton	Mandated by the Act.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	State directed.
S. 1276 - Bingaman	State directed.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	State directed.
How Soon after Enactment if State Chooses to Implement	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Six months to 2 years. State may elect retail choice in accordance with the Act no later than January 15, 2000; the election to be made by the state regulatory authority with jurisdiction over regulated electric utilities. Election made by notifying FERC within 6 months after enactment of Act. If additional legislative authority needed, 6-month date may be extended to 2 years after enactment. Nothing in the Act prohibits a state or a nonregulated utility from establishing retail competition prior to January 15, 2000.
H.R. 1230 - DeLay	
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	

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S. 237 - Bumpers	State may authorize retail access sooner. State or state regulatory authority may require retail providers to provide reasonable and nondiscriminatory access, on an unbundled basis, to local distribution and retail transmission facilities. Nonregulated providers may also elect to provide reasonable and nondiscriminatory access, on an unbundled basis, to local distribution and retail transmission facilities prior to the start date. Legislation enacted by a state prior to January 30, 1997, which has the effect of requiring retail electric competition on or before December 15, 2003, shall be deemed to be in compliance with the Act.
S. 1401 - Bumpers/Gorton	State may authorize retail access sooner. State or state regulatory authority may require retail providers to provide reasonable and nondiscriminatory access, on an unbundled basis, to local distribution facilities and all ancillary services. Legislation enacted by a state which provides all consumers within the state with the opportunity to purchase retail electricity competitively by January 1, 2002, and provides electric utility companies with the opportunity to recover their retail stranded costs shall be deemed to be in compliance with the Act.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	
Rules for Implementation (Minimum Requirements)	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	State promulgated. If state elects retail competition, state regulatory authority shall establish rules for regulated electric utilities allowing all retail customers to purchase electricity from any person offering electric services. Any person seeking to provide such services shall have reasonable, nondiscriminatory access on an unbundled basis to local distribution facilities owned or operated by regulated utilities. Access shall be under rates, terms, and conditions that are just, reasonable, not unduly discriminatory, and permit recovery of all costs associated with local distribution. Local distribution services must be at least equal in quality to those the utility provides to itself or any affiliate. Noncompetitive services may not be used to subsidize competitive services. State regulatory authority shall implement appropriate, flexible pricing procedure and incentive-based regulation for each retail service provided by a regulated utility. State shall cease to regulate retail prices or depreciation charges of any entity not providing local distribution service or in any geographic area subject to effective competition even if regulated utilities are providing local distribution.
H.R. 1230 - DeLay	No federal, state, or local government may regulate price, terms, or conditions of service offered by electric service providers (essentially defined as everything other than transmission or distribution) or who may engage in selling electric energy. If nondiscriminatory unbundled rates are not in effect when the Act takes effect, interim rates shall apply for local distribution until state rates take effect. By January 1, 1999, FERC shall promulgate rules for nondiscriminatory access to transmission and distribution service and eliminate barriers to competitive service caused by existing contracts and arrangements between transmitting utilities and distribution facilities and between transmitting utilities and any other entities. Within 3 months of enactment, FERC shall report to Congress on its plan for implementing the Act, including potential obstacles to full and reasonably expeditious implementation. FERC may also publish preliminary, nonbinding guidelines to facilitate timely compliance.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	In order to qualify for PUHCA and PURPA exemption, a person selling or distributing electric energy must meet the federal retail competition standard and the public benefit certification requirements. The federal competition standard requires all retail electric energy services, including metering and billing, to be sold and billed separately and open to competition. The opportunity to own, build, or operate new generating capacity in the state must be open to competition. The seller must not gain any undue advantage over other competitors by virtue of ownership of a monopoly distribution franchise or status as a regulated buyer and seller of electricity in a designated service territory. Tariffs must be in effect for transmission of electric energy through all local distribution facilities owned or controlled by the seller and subject to state jurisdiction and must be comparable to rates for energy transmission sold by the seller. If the seller owns, operates or controls local distribution facilities, the seller must permit reasonable and nondiscriminatory access to such facilities to enable other persons to provide retail electric energy services on a competitive basis. The public benefit certification requires all suppliers of electric services to have both the incentive and opportunity to provide energy efficiency and renewable energy resources. The state must have imposed a nonbypassable charge on the use of or access to electric energy services or facilities. Such charges must be adequate to ensure sustained and equitable allocation of costs associated with low-income services and renewable energy investments. The charges must include temporary charges to cover utility workforce transition and retraining necessitated by competition. In lieu of charges the state may establish minimum portfolio standards. Any rules applicable to retail competition among suppliers must protect customers from price discrimination or undue price increases and ensure that if a state approves recovery of net legitimate, verifiable, nonmitigatable stranded costs, no customer class can avoid paying its equitable share

COMPARISON OF PROPOSED FEDERAL ELECTRIC RESTRUCTURING LEGISLATION (Revised July 1998)	
	of such costs. Recovery of stranded costs must not be contingent on continued operation of a generation asset. The state law must require all persons providing retail electric service to have met minimum qualifications for public safety and continued reliability. State law must also provide a reasonable opportunity to aggregate for the purpose of electric purchases. A seller must also offer to purchase all electric energy generated at the retail location by a retail consumer using renewable energy resources. FERC must establish criteria for issuance by a state regulatory authority of a state certification of compliance with the standards and requirements for competition. Such criteria must provide that the state may only issue a certificate if the person meets the federal retail competition standard, the public benefit certification requirement, and such other requirements as FERC prescribes.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	State promulgated. Nothing in Act prohibits state from imposing requirements, on persons selling retail energy, which are intended to promote the public interest, including requirements for reliability and provision of information to consumers and suppliers. Such requirements must be nondiscriminatory and may not exclude any class of potential suppliers. Nothing in Act prohibits state from enacting laws or imposing regulations that are consistent with the Act.
S. 1401 - Bumpers/Gorton	All persons seeking to sell retail electric energy shall have reasonable and nondiscriminatory access, on an unbundled basis, to the local distribution and retail transmission facilities of all retail electric energy providers and all ancillary services. A state or state regulatory authority that provides for retail competition may preclude any retail provider and its affiliates from selling retail energy to consumers in the state if the provider does not allow reasonable and nondiscriminatory access, on an unbundled basis, to its local distribution facilities to any retail supplier. A state or a state regulatory authority may impose requirements on persons seeking to sell retail energy in that state which are intended to promote the public interest, including requirements related to generation reliability and provision of information to consumers and other retail suppliers. Such requirements must be applied on a nondiscriminatory basis and may not be used to exclude any class of potential suppliers. FERC may take such actions as it deems necessary to prohibit any retail or wholesale electric supplier, or any affiliate, from using its ownership or control of resources to maintain a situation inconsistent with effective competition among retail and wholesale suppliers.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	Regulation of the rates, terms, and conditions of selling electricity for end use is the exclusive jurisdiction of the states.
S. 1276 - Bingaman	If a state permits or requires an electric utility to provide unbundled, local distribution service, the utility shall provide such service on a not-unduly-discriminatory basis. Any law, regulation, or order of a state or state commission that results in unbundled, local distribution service that is unjust, unreasonable, unduly discriminatory, or preferential is preempted.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	Most areas remain under state control; however, FERC has have enhanced powers over mergers, market power issues, reliability, and ISOs.
Federal Backstop for Retail Access Implementation (FERC)	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Yes. If state elects not to implement retail access FERC shall implement retail competition for the state using the same minimum requirements specified above. FERC's exercise of such authority preempts any inconsistent state law.
H.R. 1230 - DeLay	FERC has the primary responsibility for retail access implementation.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	No, except for stranded costs. If state fails to calculate stranded cost recovery as provided in the Act, FERC must order retail energy providers to sell all generating facilities and the stranded cost recovery becomes the difference between the book value of the facilities less the amount received from their sale.

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S. 1401 - Bumpers/Gorton	The Act itself mandates retail access. However, in regard to stranded costs, if a state regulatory authority fails to determine the total stranded costs of an electric utility after a request from the utility to do so, or does not provide for full recovery of retail stranded costs, within 18 months after the utility request, FERC shall determine the utility's stranded costs.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	Federal Government must address matters within federal jurisdiction as necessary to promote competition, but such actions must not be made at the expense of state authority.
S. 1276 - Bingaman	No rule or order issued under the Act shall require or be conditioned upon the transmission of electric energy directly to an ultimate consumer unless the seller is permitted or required under applicable state law to make such sale. No rule or order shall require or be conditioned upon the transmission of electricity to or for the benefit of an electric utility if the energy would be sold by the utility directly to an ultimate consumer, unless the utility is permitted or required by state law to sell electric energy to such ultimate consumer.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	FERC has "backup" authority to establish a stranded cost recovery mechanism if a state lacks such authority.
Nonregulated Utilities Requirements (Munis and Co-ops)	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Same as regulated utilities, except that if nonregulated utility does not make an election to implement retail access and the state does make the election, nonregulated utility shall be subject to the election made by the state.
H.R. 1230 - DeLay	Same as regulated utilities.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	One year after enactment all rules adopted by FERC under Section 201, 205, or 206 of the FPA that are applicable to wholesale or retail open-access transmission services of public utilities, shall apply to any such services provided by any transmitting utility that is not a public utility and to any federal power marketing agency, in the same manner and to the same extent as to public utilities. FERC may exempt an entity from such rules if it is in the public interest.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	Same as regulated utilities.
S. 1401 - Bumpers/Gorton	Same as regulated utilities. A municipal or rural electric cooperative that seeks to recover retail stranded costs may determine its total retail stranded costs. A municipal utility or retail electric cooperative is entitled to full recovery of retail stranded costs over a reasonable period of time through a nonbypassable Stranded Cost Recovery Charge imposed on its customers. A rural electric cooperative which sells wholesale energy to rural electric cooperative retail providers, or a joint action agency which sells wholesale electric energy to municipal retail electric providers, may recover wholesale stranded costs from such rural electric cooperative or municipal retail providers.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	Same as regulated utilities.
S. 1276 - Bingaman	The definition of "public utility" is expanded to include any electric utility or federal power marketing agency not otherwise subject to FERC, including Tennessee Valley Authority; federal power marketing agency; state or political subdivision; an agency, authority or instrumentality of a state or political subdivision; any corporation or association that ever received a loan for electric service from the Rural Electrification Administration or the Rural Utilities Service; or any corporation or association wholly owned, directly or indirectly, by any one or more of the foregoing. FERC jurisdiction only extends to determining, fixing, and otherwise regulating the rates, terms, and conditions for the transmission of electric energy. The term "transmitting utility" is defined to mean any electric utility, qualifying cogeneration facility, qualifying small power production facility, federal power marketing agency, or any public utility that owns or operates electric power transmission facilities used for the sale of electric energy.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	

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S. 2287 [Clinton]	FERC's open-access rules apply to municipal utilities, cooperatives, the TVA, and PMAs. FERC has authority to ensure that transmission rates, terms and conditions of these entities are not unjust or unreasonable. FERC can suspend or modify its open-access transmission rules in respect to TVA, PMAs and rural coops with outstanding loans from the Rural Utilities Service if FERC finds they do not yet have adequate stranded cost recovery mechanisms.
Standards of Competition Statutorily Defined	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	No, but bill explicitly removes barriers to market entry and abolishes price regulation. No state or local requirement, other than a facility siting requirement, may prohibit any entity offering any retail electric service. State or local government may impose requirements on retail services necessary to ensure adequate service is available to all customers, protect public safety and welfare, ensure continued quality, and safeguard consumer rights so long as such requirements are nondiscriminatory and competitively neutral. State or local government may impose or collect any franchise, license, permit fee, or equivalent from any person providing any retail service if done on a nondiscriminatory and competitively basis. Limitations are placed on the resale of federal preference power.
H.R. 1230 - DeLay	No federal, state, or local government may regulate price, terms, or conditions of service nor who may engage in selling electric energy. Every person is guaranteed the right to purchase electric service from any provider, notwithstanding any other law. No federal, state, or local authority may deny or limit a person's right to purchase electric energy nor discriminate against any person who exercises their right to purchase. No federal, state, or local authority may grant any preference or protection from competition to any provider, including any direct or indirect subsidy, any exit fee or other levy imposed on a purchaser who terminates an existing purchasing relationship, other than a nondiscriminatory access charge for funding lifeline programs. Any alternative purchase of energy shall be consistent with regional or national reliability standards. FERC shall ensure that existing utilities do not exercise market power and will initiate proceedings on or before January 1, 1999, to determine the extent to which existing utilities have market power. FERC shall consider means for mitigating such market power and shall have the authority to restrict a utility or an affiliate from selling services at market determined rates in areas where the utility has market power and shall have authority to order divestiture of assets and functions that are the source of market power to the extent reasonably necessary to mitigate market power. Such divestiture may include outright sale, lease, or use of output contracts.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	In order to qualify for PUHCA and PURPA exemption, a person selling or distributing electric energy must meet the federal retail competition standard and the public benefit certification requirements. The federal competition standard requires all retail electric energy services, including metering and billing, to be sold and billed separately and open to competition. The opportunity to own, build, or operate new generating capacity in the state must be open to competition. The seller must not gain any undue advantage over other competitors by virtue of ownership of a monopoly distribution franchise or status as a regulated buyer and seller of electricity in a designated service territory. Tariffs must be in effect for transmission of electric energy through all local distribution facilities owned or controlled by the seller and subject to state jurisdiction and must be comparable to rates for energy transmission sold by the seller. If the seller owns, operates or controls local distribution facilities, the seller must permit reasonable and nondiscriminatory access to such facilities to enable other persons to provide retail electric energy services on a competitive basis. The public benefit certification requires all suppliers of electric services to have both the incentive and opportunity to provide energy efficiency and renewable energy resources. The state must have imposed a nonbypassable charge on the use of or access to electric energy services or facilities. Such charges must be adequate to ensure sustained and equitable allocation of costs associated with low-income services and renewable energy investments. The charges must include temporary charges to cover utility workforce transition and retraining necessitated by competition. In lieu of charges the state may establish minimum portfolio standards. Any rules applicable to retail competition among suppliers must protect customers from price discrimination or undue price increases and ensure that if a state approves recovery of net legitimate, verifiable, nonmitigatable stranded costs, no customer class can avoid paying its equitable share of such costs. Recovery of stranded costs must not be contingent on continued operation of a generation asset. The state law must require all persons providing retail electric service to have met minimum qualifications for public safety and continued reliability. State law must also provide a reasonable opportunity to aggregate for the purpose of electric purchases. A seller must also offer to purchase all electric energy generated at the retail location by a retail consumer using renewable energy resources. FERC must establish criteria for issuance by a state regulatory authority of a state certification of compliance with the standards and requirements for competition. Such criteria must provide that the state may only issue a certificate if the person meets the federal retail competition standard, the public benefit certification requirement, and such other requirements as FERC prescribes.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	No, but state may impose requirements to promote public interest as long as they are nondiscriminatory and do not exclude any class of potential providers. FERC to take any necessary action to prohibit providers from

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	creating situation inconsistent with effective competition among retail and wholesale suppliers. Act prohibits providers from recovering in distribution and retail transmission rates any costs associated with unregulated activities. FERC authorized to approve mergers between electric and natural gas utility company.
S. 1401 - Bumpers/Gorton	No, but state may impose requirements to promote public interest as long as they are nondiscriminatory and do not exclude any class of potential providers. FERC to take any necessary action to prohibit providers from creating situation inconsistent with effective competition among retail and wholesale suppliers. FERC authorized to approve mergers between electric and natural gas utility company.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	Congress should consider restricting governmental utilities with respect to facilities financed with tax-exempt debt. Sales in a service territory in existence before the restriction may continue to be financed using tax-exempt debt. A governmental utility should have to finance sales outside its service territory on the same basis as other competitors.
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	States have the right to determine if they will allow retail competition and, if so, on what terms and conditions. However, FERC is authorized, upon petition from a state, to remedy market power in retail markets if the state is implementing retail competition, determines that market power exists, and has insufficient authority to address market power. FERC is authorized to require generators with market power to submit a plan to mitigate market power, which FERC can approve with or without modification. FERC is authorized to order divestiture to the extent necessary to mitigate market power. On its own motion or by complaint, FERC can remedy market power in wholesale markets. FERC is also authorized to require transmitting utilities to turn over operational control of transmission facilities to an ISO.
Treatment of Stranded Costs	
H.R. 338 - Stearns	Allows full recovery of all costs prior to January 7, 1997, associated with utility purchases from QFs mandated by Section 210. FERC to adopt necessary regulations.
H.R. 655 - Schaefer	Preserves state authority to deal with problem as appropriate. State regulatory authority shall consider and make a determination concerning whether or not it is appropriate to allow regulated utilities to recover costs incurred prior to July 11, 1996, including costs of PURPA contracts. State may require, as a condition for retail access, payment of a charge deemed necessary by the state to recover costs unrecoverable due to retail competition. Nonregulated utilities may also impose a similar charge.
H.R. 1230 - DeLay	Prohibits the recovery of stranded costs (*).
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	Any rules applicable to retail competition among electric service suppliers must protect customers from price discrimination or undue price increases and ensure that if a state approves recovery of net legitimate, verifiable, nonmitigatable stranded costs, no customer class can avoid paying its equitable share of such costs.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	Requires 100 percent recovery. Act provides two methods of calculating stranded costs: (1) all legitimate, prudently incurred, and verifiable investments in generation assets, including power purchase contracts, and related regulatory assets that would have been recoverable but for retail competition, which cannot be reasonably mitigated; or (2) retail provider sells all generating facilities and the difference between book value of such facilities and amount received from sale is the stranded cost. Previous state determination of prudence may not be reassessed. FERC is backstop if state allows less than full recovery; FERC must use the second method of calculation. Special procedure for creation of regional boards to handle multistate utility stranded costs.
S. 1401 - Bumpers/Gorton	Retail stranded costs are defined as all legitimate, prudent, verifiable, and nonmitigatable costs incurred by an electric utility in all of its generation assets which would have been recoverable in retail rates but for the implementation of retail competition, less the total market value of these assets after competition is implemented. Binding power purchase contracts and regulatory assets, the costs of which would have been recovered but for the implementation of retail electric competition, shall be considered generation assets. A utility subject to the rate making jurisdiction of a state authority prior to enactment of the Act may submit an application to the state authority seeking a determination of its total stranded costs in that state if the state has enacted retail competition which does not provide for full recovery of retail stranded costs. If the state authority fails to determine the utility's stranded costs within 18 months after application, FERC shall determine the utility's stranded costs. FERC has sole jurisdiction to determine and provide for recovery of wholesale stranded costs. Creation of regional boards is authorized if: (1) each state regulatory authority having jurisdiction over an affiliate of a public utility holding

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	company elects to join; (2) an affiliate owns or operates a generating facility and sells power to two or more affiliates of the same holding company and did not sell retail energy prior to January 30, 1997; (3) the holding company notifies each state regulatory authority that it intends to seek recovery of wholesale stranded costs associated with the generating facilities affiliated with the holding company. The regional board must be formed within six months after receiving notification from each state regulatory authority that they elect to create such a board. If the elections are not made within that time period, FERC shall assume the responsibilities of the board. The regional board has 18 months after its formation to unanimously determine the wholesale stranded costs associated with the generating facility and to allocate such costs among the affiliates on a just and reasonable, nondiscriminatory basis. If the board fails to make such a determination, FERC shall make it. After the determination of the wholesale stranded costs, the affiliate shall be entitled to fully recover its stranded costs, over a reasonable period of time from the retail electric energy provider affiliates to which it sells electricity. A state may require a retail provider to compensate its retail customers in the event that negative stranded costs arise as a result of the market price of electricity exceeding the value of assets in the rate base prior to competition. Any retail and wholesale supplier owning nuclear generating units prior to enactment of the Act shall recover all reasonable costs as determined by FERC, and the relevant state authorities, associated with federal and state requirements for decommissioning. Such costs are recoverable through a nonbypassable charge imposed on all consumers located in the service territories purchasing power, or that had purchased power, from such nuclear generating units.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	The transition to competition should not impair the ability of states to determine recovery of the substantial investments made by electric utilities to serve customers. A state or nonregulated utility may require, as a condition of the purchase of a retail electric supply or local distribution service, by any person or municipality located in the state or service area of the nonregulated utility, as appropriate, the payment of a charge determined by the state or nonregulated utility to further public policy goals including recovering electric industry transition costs.
S. 1276 - Bingaman	Nothing in the Act prohibits a state or state regulatory authority from assessing a nondiscriminatory charge on unbundled, local distribution service within the state, the retail sale of electric energy within the state, or the generation of electric energy for consumption by the generator within the state. No state or state regulatory authority may bar a state regulated electric utility from recovering the cost of electric energy the utility is required to purchase from a qualifying cogeneration facility or qualifying small power production facility under this section. Nothing in the Act shall prohibit a state regulatory authority from assessing a nondiscriminatory charge on unbundled, local distribution service within the state, the retail sale of electric energy within the state, or the generation of electric energy for consumption by the generator within the state.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	Utilities should be able to recover prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated. States retain the authority to determine stranded cost recovery. The use of competitively neutral mechanisms that minimize any impact on the choice of supplier is encouraged. FERC has "backup" authority to establish a stranded cost recovery mechanism if a state lacks such authority.
Conditions Imposed on Stranded Cost Recovery	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Recovery terms and conditions must be nondiscriminatory and competitively neutral; only costs incurred prior to July 11, 1996, are covered.
H.R. 1230 - DeLay	
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	Prohibits any customer class from bypassing stranded cost recovery; recovery is not contingent on continued operation of the asset.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	No cost shifting between customer classes. Costs must be legitimate, prudent, verifiable, nonmitigatible, and recovered over a reasonable period of time.
S. 1401 - Bumpers/Gorton	No class of consumer shall be assessed a Stranded Cost Recovery Charge determined by a state regulatory authority or FERC, whichever is applicable, that is in excess of the classes' proportional responsibility for retail providers' costs that existed prior to the implementation of retail competition. Customers of a retail provider that serves customers in more than one state or that is affiliated with another provider, shall only be responsible for stranded costs associated with retail competition in the state or area in which such customers are located. Costs

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	must be legitimate, prudent, verifiable, nonmitigatable, and recovered over a reasonable period of time.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	
S. 1276 - Bingaman	Nothing in the Act prohibits a state or state regulatory authority from assessing a nondiscriminatory charge on unbundled, local distribution service within the state, the retail sale of electric energy within the state, or the generation of electric energy for consumption by the generator within the state.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	Utility must take all reasonable steps to mitigate stranded costs.
Transmission Pricing and Federal/State Jurisdiction of "Wires"	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Codifies relevant provisions of FERC's Order 888. Providers of unbundled retail transmission or distribution in interstate commerce must obtain a jurisdictional determination from FERC regarding which of their facilities are FERC jurisdictional and which are subject to state jurisdiction. FERC to make determination within 18 months after application is filed by current provider; determination to be made within 1 year after application filed by new provider. In making jurisdictional determination, FERC shall consider the seven factors listed in Order 888 and historical uses of facilities. FERC shall defer to state commission recommendations that take the foregoing factors into account. Once FERC makes determination, decision may not be modified unless there is a material change in facts since the prior determination. Aggrieved parties may seek review in the Circuit Court of Appeals. Federal courts have exclusive jurisdiction over actions arising under Section 106.
H.R. 1230 - DeLay	Transmission and distribution systems shall be operated to achieve: (1) organizational separation within vertically integrated firms, between individuals, assets, and systems used in transmission and distribution and those involved in the provision of electric service; (2) nondiscriminatory access for wholesale or retail service; (3) prevention of preferential treatment by system operators towards affiliated providers; (4) nondiscriminatory access to information on availability of transmission and distribution service, operating conditions, rates, terms and conditions of arrangements between system operators and affiliates; (5) ensuring that transmission and distribution system operator receives adequate and timely information from providers about physical flows and physical transactions, has access to assets needed to maintain system balance, and has authority to implement FERC approved sanctions and penalties for nonconformance. FERC shall have authority to provide nondiscriminatory prices, terms, and conditions of transmission and distribution service but shall defer to state regarding local distribution service.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	Within 12 months after enactment, FERC shall promulgate rules to establish tariffs in the largest region or regions feasible to ensure full recovery by owners of transmission facilities of all prudent transmission costs and prevent multiple charges for transmission service based on the number of transmission owners. Additionally, FERC rules must prevent any person engaged in the sale of energy from gaining any advantage over competitors by reason of ownership or control of transmission or distribution facilities. Effective 1 year after enactment, all FERC rules under Sections 201, 205, or 206 of the FPA that are applicable to wholesale or retail open-access transmission services of public utilities shall apply to any such services provided by any transmitting utility and to any federal power marketing agency in the same manner and to the same extent as such rules apply to public utilities.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	FERC to establish broadest feasible transmission regions and designate ISO for each region to commence operation on December 15, 2003. States in each region may elect to form a Regional Oversight Board with same powers as FERC regarding transmission within region. If states do not form board, FERC retains authority over transmission between regions.
S. 1401 - Bumpers/Gorton	A state regulatory authority may apply to FERC for a determination whether a particular facility used for transportation of electricity in that state is a local distribution facility subject to state jurisdiction or is a transmission facility subject to FERC jurisdiction. In making its determination, FERC shall give maximum practical deference to the position taken by the state authority in accordance with seven specified factors associated with the facility. Within two years after enactment, FERC shall establish the broadest feasible transmission regions and designate an ISO to manage and operate the transmission system in each region beginning on January 1, 2002. FERC shall give deference to ISO operators approved by FERC prior to enactment. An ISO shall not be subject to the control of any person owning any transmission facility located in the ISO region or subject to the control of any retail supplier selling electricity in the ISO's region. FERC shall continue to have authority over transmission in interstate commerce by the ISOs and shall have authority over

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	transmission in interstate commerce between two or more transmission regions. On or before January 1, 2001, FERC shall issue binding rules governing ISOs and designed to promote reliability, efficiency, and competition among retail and wholesale suppliers.
S. 621 - D'Amato	
S. 687 - Jeffords	
S. 722 - Thomas	A contract for wholesale sale of electric energy after the date of enactment shall be exempt from the regulation of rates and charges. A transmitting utility and any other entity that owns, operates, or controls transmission in interstate commerce shall be subject to the jurisdiction of FERC regarding any wholesale transmission service. A person may not provide any wholesale electric supply in commerce using open and nondiscriminatory transmission access unless the person, and every affiliate, provides comparable open and nondiscriminatory transmission access to any facility owned, controlled, or operated by the person or affiliate.
S. 1276 - Bingaman	FERC jurisdiction over transmission is expanded to include unbundled transmission of electric energy sold at retail. However, FERC regulation shall not extend to bundled retail sale of electric energy or to unbundled, local distribution service that is subject to regulation by the state. After consultation with the appropriate state regulatory authorities, FERC shall determine which facilities used for transmission and delivery are in interstate commerce and subject to FERC jurisdiction and which are used for local distribution and subject to state jurisdiction. FERC jurisdiction over open access to transmission lines is extended to lines that cross borders with Mexico and Canada. FERC shall establish and enforce national electric reliability standards. FERC may designate an appropriate number of regional electric reliability councils composed of electric utilities or transmitting utilities and may establish one national electric reliability council comprised of designated regional electric reliability councils. FERC shall not designate a regional electric reliability council unless FERC determines that the council permits open access to membership from all entities engaged in selling, generating, transmitting, or delivering electric energy within the region, provides fair representation in selection of directors and management and adopts and enforces appropriate standards of operation to promote reliability. FERC may incorporate the standards adopted by regional and national councils in the national standards adopted by FERC. FERC may require any public utility or transmitting utilities to comply with any standard adopted by FERC. A "transmitting utility" is defined as any electric utility, qualifying cogeneration facility, qualifying small power production facility, federal power marketing agency, or any public utility that owns or operates electric power transmission facilities used for the sale of electric energy. FERC, after notice and hearing, may order a transmitting utility to enlarge, extend, or improve facilities for interstate transmission. FERC may commence such a proceeding on its own motion, upon application of an electric utility, a transmitting utility, or a state regulatory authority. Before issuing such an order, FERC must refer the matter to a joint board for advice and recommendation on the need for, design of, and location of a proposed enlargement, extension, or improvement. FERC shall have no authority to compel a transmitting utility to extend or improve its facilities if enlargement, extension, or improvement would unreasonably impair the ability of the utility to render adequate service to its customers. FERC may order the formation of a regional transmission system and may order any transmitting utility operating within such region to participate in the regional system. FERC shall appoint a regional oversight board to oversee the regional transmission system. The board must be composed of fair representation of all transmitting utilities in the regional system, electric utilities, and consumers served by the system, and state regulatory authorities within the region. The board shall appoint an independent system operator to operate the regional transmission system. No ISO shall own generation facilities or sell electric energy or be controlled by or have a financial interest in any electric utility or transmitting utility within the region. The board shall ensure that the ISO formulates policies, operates the system and resolves disputes in a fair and nondiscriminatory manner.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	No supplier of electric energy, who would otherwise have a right of access to a transmission or local distribution facility because such facility is an essential facility for the conduct of interstate commerce in electric energy, shall be denied access to such facility or precluded from engaging in the retail sale of electric energy on the grounds that such denial or preclusion is authorized or required by state action establishing, maintaining, or enforcing an exclusive right to sell, transmit, or locally distribute electric energy. Nothing in the Act authorizes FERC to regulate retail sales or local distribution of electric energy.
S. 2287 [Clinton]	Federal Power Act is amended to give FERC authority to approve the formation of and oversee a private self-regulatory organization that prescribes and enforces mandatory reliability standards. FERC has authority to require transmitting utilities to turn over operational control of transmission facilities to an ISO. FERC has clear authority to order retail transmission in a transmission system to complete an authorized retail sale. FERC's jurisdiction is reinforced over terms, rates, and conditions of unbundled retail transmission. FPA is amended to clarify that it does not preempt states from ordering retail competition. Grants states or nonregulated utilities that have implemented retail competition the authority to preclude an out-of-state utility with a retail monopoly from selling within the state or service territory unless the out-of-state utility permits customer choice. FPA is amended to clarify that states are not preempted from imposing a charge on the ultimate consumers' receipt of electric energy. Amends federal law to allow the development of a regional transmission planning agency to facilitate coordination among states within a particular region regarding future transmission, generation and distribution facilities and to assist states with siting responsibilities.
PUHCA Repeal	

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H.R. 338 - Stearns	
H.R. 655 - Schaefer	Repeals PUHCA on company-by-company basis, i.e., after retail access has been implemented in all states served by the company. Each state in which a PUHCA utility provides electric energy at retail makes the determination whether full retail access is available.
H.R. 1230 - DeLay	PUHCA shall cease to apply to a utility or holding company if each state in which the utility provides energy services determines retail customers served by the utility and its affiliates have open access to retail services.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	Exempts a utility from PUHCA if the utility qualifies for a "certificate of compliance."
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	This Act shall take effect 12 months after date of enactment. Not later than 12 months after enactment, FERC shall promulgate regulations to implement the Act and submit to Congress detailed recommendations on technical and conforming amendments to federal law. Not later than 90 days after enactment, FERC shall promulgate a rule exempting holding companies from certain provisions of the Act with respect to QFs under PURPA, exempt wholesale generators or foreign utility companies.
H.R. 4183 - Solomon	
S. 237 - Bumpers	PUHCA repeal effective 1 year from the date of enactment.
S. 1401 - Bumpers/Gorton	Same as S. 237.
S. 621 - D'Amato	Not later than 18 months after enactment, FERC shall promulgate regulations to implement the Act and submit to Congress detailed recommendations on technical and conforming amendments to federal law.
S. 687 - Jeffords	
S. 722 - Thomas	Repeals PUHCA.
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	Repeals substantive requirements of PUHCA and provides FERC and state commissions with additional access to books and records of holding companies and affiliates of public utilities within holding companies to assist in guarding against interaffiliate abuse.
PURPA Repeal	
H.R. 338 - Stearns	After January 7, 1997, no electric utility required to enter into a new contract pursuant to Section 210. Nothing in Act affects rights or remedies under any contract in effect on January 7, 1997.
H.R. 655 - Schaefer	Suspends mandatory purchase requirement after state PUC determines that retail competition has been established. Preserves existing contracts and other PURPA Section 210 provisions.
H.R. 1230 - DeLay	Section 210 shall cease to apply to an electric utility if each state in which the utility provides electric service determines that retail customers served by the utility have access to retail competition. Nothing in the Act affects any obligation under a binding contract entered into prior to enactment.
H.R. 1359 - DeFazio	Amends Title VI of PURPA by adding a new section, 605, titled "National Electric System Public Benefits Fund."
H.R. 1960 - Markey	Section 210 does not apply to any contract entered into by an electric utility during any period for which a certification of competition from a state regulatory authority is in effect. A state regulatory authority may elect to require any seller or distributor to comply with standards and requirements of competition pursuant to the Act. Such election shall be voluntary. When the seller has complied with the standards and requirements of competition, the state authority shall issue a certificate of compliance. FERC shall establish criteria for the issuance of a state certification of compliance. Such criteria shall provide that the state may issue a certificate only if the person meets the federal retail competition standard, the public benefit certification requirements, and such other requirements as FERC prescribes.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	Amends PURPA to ensure that rates charged by qualifying, small power producers and qualifying co-generators do not exceed the incremental cost to the purchasing utility of alternative electric energy at the time of delivery. Clarifies that states have the authority to establish programs for monitoring the operating and efficiency performance of in-state cogeneration and small power production facilities for the purpose of determining whether such facilities meet FERC standards for qualifying facilities. Nothing in the Act or any other provision of law shall prohibit a state or FERC from ensuring that all costs associated with the purchase of electric energy from QFs pursuant to PURPA are recovered by the purchaser.

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S. 237 - Bumpers	Section 210 shall not apply to any facility that begins commercial operation after effective date except facility under a contract that was in effect on date Act passed. After effective date of Act, no public utility required to enter into new contract or obligation pursuant to Section 210. Act does not give FERC or state authority to force renegotiations of existing PURPA contracts.
S. 1401 - Bumpers/Gorton	Same as S. 237.
S. 621 - D'Amato	
S. 687 - Jeffords	Effective January 1, 2000, Section 210 is repealed; however, the validity and enforceability provisions of existing contracts entered into prior to the effective date of the Act are not affected.
S. 722 - Thomas	Amends Section 210 to provide that the section shall not apply to a facility that begins commercial operation after the date of enactment except for a facility for which a power purchase contract was entered into before the date of enactment. After enactment, an electric utility shall not be required to enter into a new contract or obligation to purchase or sell electric energy pursuant to Section 210.
S. 1276 - Bingaman	No state or state regulatory authority may bar a state regulated electric utility from recovering the cost of electric energy the utility is required to purchase from a qualifying cogeneration facility or qualifying small power production facility.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	Repeals prospectively the "must buy" provision of Section 210 of PURPA, but preserves existing contracts and exemptions.
Interaffiliate Transactions Within Holding Companies	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Every holding company, associate company, and affiliate must maintain and make available to FERC books, accounts, documents, and other records FERC deems relative to costs incurred by a public utility or natural gas company. Upon written request of a state commission having jurisdiction over a public utility company in a holding company system, and subject to terms and conditions necessary to safeguard against unwarranted disclosure to the public of trade secrets or sensitive commercial information, a holding company, associate, or affiliate, wherever located, must produce for inspection books, account, documents, and other records that are relevant and necessary for effective discharge of state commission responsibilities.
H.R. 1230 - DeLay	
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	A person may not acquire any interest in a public utility company that results in ownership of a substantial interest and effective control of such company unless FERC makes findings that the acquisition will not create or maintain a situation inconsistent with effective competition in any market in which competition would benefit consumers, that the acquisition will result in substantial cost reductions that are greater than could be achieved without the acquisition and that the acquisition will be entered into on an arm's length basis. A public utility company or an affiliate may not use ownership or control of any resource to create or maintain a situation inconsistent with effective competition in the purchase and sale of electric energy or natural gas in any market in which the company or affiliate has a designated service territory for retail distribution. Whenever FERC finds a violation it may order the sale or other transfer of assets to a nonaffiliated company, to an affiliated company, or may require the conduct of business activities on an arm's length basis. FERC and each state commission having authority over retail sales of electric energy or natural gas must have access to the books and records of the public utility and all affiliates necessary to ensure that competitive conditions are met and continue to be met. No contract having a total value of $1 million or more entered into after the effective date between a public utility and an affiliate shall be valid unless each state commission having authority over retail sales of electric energy or natural gas has found that the contract will have no adverse effect on consumers and the state commission has the authority and resources to prevent any such adverse effect.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	The term "affiliate" of a company means any company 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company. The term "holding company" means any company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities of a public utility company or of a holding company of any public utility company and any person determined by FERC to exercise directly or indirectly such a controlling influence over the management or policies of any public utility company or holding company as to make it necessary or appropriate for the rate protection of utility customers that such person be subject to the Act. Holding companies must maintain certain books and records and make them available to FERC and state commissions if FERC or a state commission deems they are relevant to certain costs incurred by public utility companies that are associate companies of holding companies or that involve transactions with another affiliate. Nothing in the Act precludes FERC or a state commission from exercising jurisdiction to determine whether a

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	public utility company may recover in rates any costs of an activity performed by an associate company or any costs of goods or services acquired by such public utility company from an associate company.
H.R. 4183 - Solomon	
S. 237 - Bumpers	FERC determines whether public utility company may recover in wholesale rates any costs of goods and services acquired by the utility from an associate company after July 1, 1994. State commission has similar authority respecting retail rates. State has authority to examine prudence of wholesale electric power purchase by public utility that is not associate company of public utility if the public utility provides retail service subject to regulation by the state. No public utility that is associate company of a holding company may recover any costs not associated with provision of electric service unless FERC consents as to wholesale rates or state gives consent as to retail rates. Holding companies and associate companies required to maintain and make available to FERC and state commissions books, records, accounts, and other documents relative to cost determinations. No such information may be released by FERC or state unless otherwise directed by FERC, state commission, or a court. Act does not apply to holding company and associate company if FERC determines retail customers of every public subsidiary of a holding company have access to retail competition in a manner that no longer requires regulation of the holding company.
S. 1401 - Bumpers/Gorton	Certain provisions shall not apply to a holding company and every associate company if FERC certifies that retail customers of every public utility subsidiary of such holding company have access to retail electric competition and each state regulatory authority certifies that they will have sufficient access to the holding company's books and records relevant to the state's regulatory responsibility. Otherwise, the same as S. 237.
S. 621 - D'Amato	The term "affiliate" of a company means any company 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company. The term "holding company" means any company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities of a public utility company or of a holding company of any public utility company and any person determined by FERC to exercise directly or indirectly such a controlling influence over the management or policies of any public utility company or holding company as to make it necessary or appropriate for the rate protection of utility customers that such person be subject to the Act. Holding companies must maintain certain books and records and make them available to FERC if FERC deems they are relevant to certain costs incurred by public utility or natural gas companies that are associate companies of holding companies or that involve transactions with another affiliate. Nothing in the Act precludes FERC from exercising jurisdiction to determine whether a public utility company may recover in rates any costs of an activity performed by an associate company or any costs of goods or services acquired by such public utility company from an associate company.
S. 687 - Jeffords	
S. 722 - Thomas	The term "affiliate" of a company means any company 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company. The term "holding company" means any company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities of a public utility company or of a holding company of any public utility company and any person determined by FERC to exercise directly or indirectly such a controlling influence over the management or policies of any public utility company or holding company as to make it necessary or appropriate for the rate protection of utility customers that such person be subject to the Act. Holding companies must maintain certain books and records and make them available to FERC if FERC deems they are relevant to certain costs incurred by public utility or natural gas companies that are associate companies of holding companies or that involve transactions with another affiliate. Nothing in the Act precludes FERC from exercising jurisdiction to determine whether a public utility company may recover in rates any costs of an activity performed by an associate company or any costs of goods or services acquired by such public utility company from an associate company.
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2187 - Nickles	
S. 2287 [Clinton]	Repeals substantive requirements of PUHCA and provides FERC and state commissions with additional access to books and records of holding companies and affiliates of public utilities within holding companies to assist in guarding against interaffiliate abuse.
Renewable Energy Resources	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Establishes tradable credits program; mandates minimum market shares for renewables. Each generator that sells electricity to any other person must submit to FERC renewable energy credits equal to the required annual percentage in the preceding calendar year. Generation from hydroelectric facilities must not be taken into account. From calendar year 2001 through 2004, required annual percentage is 2 percent. Percentage increases to 3 percent in 2005 and to 4 percent in 2010. Nothing prohibits a state from requiring additional renewable energy generation by state law. Renewable energy credit program sunsets when FERC determines that the number of credits traded has declined to nominal levels.
H.R. 1230 - DeLay	

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H.R. 1359 - DeFazio	Act creates National Electric System Public Benefits Fund administered by National Electric System Public Benefits Board to provide matching funds to states for eligible public purpose programs. Eligible programs are those that support conservation, energy efficiency, renewable energy, universal and affordable service, or research and development for such purposes. "Renewable energy" is defined as electricity generated from nontoxic organic waste, bio-mass, dedicated energy crops, landfill gas, geothermal, solar, tidal or wind resources but excludes generation from incineration of municipal solid waste. Each owner or operator of an electric generation facility shall, as a condition of transmitting power to any transmitting utility, contribute funds on a per kWh basis in amounts determined by the board to be necessary each calendar year. Contributions shall not exceed 2 mills per kWh. Transmitting utilities collect contributions and transfer them monthly to a non-federal fiscal agent designated by the board. Any state may establish one or more public purpose programs and apply for matching funds. No state is required to participate and no state may be required by the board to fund a particular program. The fiscal agent shall distribute contributions to the states in accordance with criteria established by board. States seeking matching funds shall apply no later than 3 months prior to the start of the calendar year. Upon receipt of all state requests for matching funds, the board shall calculate funds necessary to match projected state expenditures. Fiscal agent shall distribute matching funds to states in monthly payments. If state requests exceed maximum projected revenues, state requests shall be prorated. The program shall not replace or supersede existing programs.
H.R. 1960 - Markey	The Act creates a minimum renewable generation requirement. Every person who generates and sells must submit to the Secretary of Energy renewable energy credits computed in kilowatt hours in specified percentages. The specified percentage for calendar year 1998 shall be 3 percent of the total sales in the preceding calendar year. The secretary shall annually establish a gradually increasing percentage for each calendar year according to a sliding scales such that the specified percentage for 2010 and thereafter is 10 percent. Nothing in the Act prohibits the state from requiring additional renewable energy generation. The Act also authorizes the Secretary of Energy to establish a program of tradeable energy credits. Such credits may not be carried forward from year-to-year. One of the public benefits certification requirements is that all suppliers of energy services to electric consumers to whom such person provides retail electric services in the state have both the incentive and opportunity to provide energy efficiency and renewable energy resources. Certification also requires a net metering program for renewable energy. Nothing in the Act prevents a state regulatory authority from making a determination for purposes of Section 210 of PURPA of incremental costs to a purchasing electric utility of alternative electric energy, from establishing incremental costs at levels that reflect avoided environmental costs not included in market rates. Disclosure rules require every contract for the sale of electric energy for resale to disclose source data for the generation.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	Establishes tradable credits program; mandates minimum market shares for renewables. Each generator must submit to FERC renewable credits equal to the required annual percentage in the preceding calendar year. Beginning in 2003, the required percentage is 5 percent; percentage increases to 9 percent in 2008, and 12 percent in 2013. Generation from hydroelectric facilities maybe used to satisfy the requirement. However, more credits are given for other forms of renewable energy. States may require additional renewable energy generation. Provisions of the Act relating to renewable energy sunset on December 31, 2019. EPA to submit report to Congress by January 1, 2000, which examines implications of differences in air pollution standards for wholesale and retail generation. Report shall recommend changes to federal law necessary to protect public health and the environment.
S. 1401 - Bumpers/Gorton	Same as S. 237.
S. 621 - D'Amato	
S. 687 - Jeffords	Act creates National Electric System Public Benefits Fund administered by National Electric System Public Benefits Board to provide matching funds to states for public purpose programs relating to renewable energy sources, energy conservation and efficiency, and research and development programs designed to support such public purpose programs. Renewable energy is defined as generation from wind, organic waste (excluding incinerated municipal solid waste), bio-mass, geothermal, solar, or photovoltaic. Board selects manager for 3-year term. Manager reviews state applications and makes recommendations to board. Board recommends eligibility criteria to Secretary of Energy. Not later than August 1 of each year beginning in 1999, state seeking matching funds shall file application with board. Not later than August 1, board shall determine aggregate amount of wires charges necessary to fund programs for the following year. Not later than December 15, FERC shall impose nonbypassable, competitively neutral wires charge to be paid directly to fund by wires operator on electricity in interstate commerce. Electricity to be measured as it exits the busbar at a generation facility. Generation facility means a non-hydroelectric facility. Wires charge shall equal lesser of 2 mills per kWh or a rate estimated to produce necessary matching funds for the given year. Wires charge shall be paid by the wires operator at the end of each month. Renewable energy portfolio standard shall equal 2.5 percent of the total amount of electricity sold by covered generation facilities in 2000. Amount increases by .5 percent per year until it reaches 5 percent in 2005. Thereafter, amount increases 1 percent a year until it reaches 20 percent in 2020. Act establishes program of tradable renewable credits.
S. 722 - Thomas	The transition to competition should not impair the ability of states to determine recovery of the substantial

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	investments made by electric utilities to serve customers. A state or nonregulated utility may require, as a condition of the purchase by any person or municipality located in the state or service area of the nonregulated utility, as appropriate, of a retail electric supply or local distribution service, the payment of a charge determined by the state or nonregulated utility to further public policy goals including encouraging environmental programs, renewable-energy programs, energy-efficiency programs, or conservation programs, or to encourage research and development on electric technologies.
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	The Secretary of Energy is authorized to conduct rule making to require all suppliers to disclose information on price, terms, and conditions, including the type of generation source and generation emission characteristics. Establishes a federal renewable portfolio standard requiring sellers to cover a percentage of sales with generation from nonhydroelectric renewable technologies. The portfolio standard is initially set close to the ratio of portfolio standard-eligible generation to retail electric sales projected under baseline conditions. There is an intermediate increase in 2005, followed by an increase to 5.5 percent in 2010. There is a system of tradable renewable credits, subject to a cost cap of 1.5 cents/kWh. All consumers eligible for net metering and all distribution service providers must assure the availability of interconnection, subject to appropriate nondiscriminatory safety standards. Eligibility limited to 20 kW units or less and can be subject to a cap determined at the state level. Part of a $3 billion per year public benefit fund is devoted to energy efficiency programs and the development and demonstration of emerging technologies, particularly renewables.
State/Local Jurisdiction	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	State or local governments may apply terms and conditions to local distribution or retail electric energy services to ensure that adequate service is available to all customers, to ensure reliability, to promote efficiency, conservation, and environmental programs. State courts have jurisdictions over actions arising under Sections 102, 103, 104, 107, and 111, except for review by the United States Supreme Court. Any person may bring an action in the appropriate state court to enforce the foregoing sections. Nothing in the Act prohibits a state or a nonregulated utility from establishing retail competition prior to January 15, 2000. Nothing in the Act preempts any state statute that is consistent with the Act.
H.R. 1230 - DeLay	Nothing in the Act affects authority of state or local government concerning obligation to connect consumers to local distribution system and to ensure adequate maintenance, safety, and reliability. State and local governments have authority to provide for lifeline service to residential customers unable to afford energy service, including authority to establish nondiscriminatory local distribution access charge to fund such programs. If consumers make no selection of an alternative provider, state may establish rules under which such customers are initially assigned on a nondiscriminatory basis to one of a variety of providers that have filed service terms with the appropriate state authority. State and local governments retain authority over any specific matter not addressed in the Act including universal service, conservation programs, renewable energy, research and development programs, and any other matter deemed appropriate by a state or local government. Judicial review of the Act or any order made pursuant to the Act must be obtained in the Circuit Court of Appeals.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	A state regulatory authority may elect to require any person selling or distributing electric energy to comply with standards and requirements of the Act. Such election is voluntary and nothing in the Act prohibits a state regulatory authority from determining that it is not appropriate to require an entity to comply with such standards and requirements. Nothing prohibits a state from implementing any other process regarding competition. State regulatory authorities have authority to issue state certification of compliance with standards and requirements for competition. After enactment no provision of federal law preempts otherwise applicable state authority to review the prudence of any wholesale or retail cost incurred by an electric utility or to determine the recovery of costs for the sale or delivery of electric energy and related services to a retail customer regardless of the facilities used. The foregoing is not applicable to any wholesale or retail costs incurred by a utility the recovery of which in wholesale rates has been approved by FERC before enactment. No provision of federal law preempts state authority to impose nonbypassable charges for use of facilities subject to state jurisdiction to ensure equitable allocation of costs associated with low-income services, energy efficiency, or minimum portfolio standards for renewable energy. An attorney general of any state may bring a civil action to enforce a FERC rule if the attorney general believes that the interests of the residents of the state are being threatened or adversely affected because of a violation.
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	Nothing in the Act prohibits state from imposing requirements on person seeking to sell retail energy that are intended to promote public interest, including reliability and information sharing on nondiscriminatory basis

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	without exclusion of any class of potential suppliers. State may continue to regulate local distribution and retail transmission service. Nothing in the Act shall preclude state from exercising jurisdiction under otherwise applicable law to protect utility consumers. Any person aggrieved by violation of the Act committed by supplier must bring an action in Federal District Court. Any person aggrieved by a state commission or FERC action must seek redress in the Circuit Court of Appeals.
S. 1401 - Bumpers/Gorton	Same as S. 237 except that states continue to regulate local distribution while FERC regulates transmission service.
S. 621 - D'Amato	A state commission with jurisdiction to regulate public utilities in a holding company system may request a holding company, its affiliate or associate wherever located to produce books and records that the state commission deems relevant to costs incurred by the public utility company. Nothing in the Act precludes a state commission from exercising jurisdiction to determine whether a public utility company may recover in rates any costs of an activity performed by an associate company or any costs of goods or services acquired by such public utility company from an associate company.
S. 687 - Jeffords	
S. 722 - Thomas	A state may regulate the provision of any retail electric supply (including self-generation) or any local distribution service provided to an ultimate consumer of electricity in the state. The sale of electric energy to a facility of a department or agency of the United States or a federally chartered corporation shall be subject exclusively to the utility laws of the state in which the facility is located.
S. 1276 - Bingaman	Neither silence on the part of Congress nor any act of Congress will preclude a state or state commission from requiring an electric utility to provide unbundled, local distribution service within such state. A state or state commission may bar an electric utility from selling electricity to an ultimate consumer using local distribution facilities if the utility or any affiliate owns or controls local distribution facilities and is not itself providing unbundled, local distribution service. Nothing in the Act shall prohibit a state or state authority from assessing a nondiscriminatory charge on unbundled, local distribution service within the state, the retail sale of electric energy within the state, or the generation of electric energy for consumption by the generator within the state.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	No supplier of electric energy, who would otherwise have a right of access to a transmission or local distribution facility because such facility is an essential facility for the conduct of interstate commerce in electric energy, shall be denied access to such facility or precluded from engaging in the retail sale of electric energy on the grounds that such denial or preclusion is authorized or required by state action establishing, maintaining, or enforcing an exclusive right to sell, transmit, or locally distribute electric energy. Nothing in the Act authorizes FERC to regulate retail sales or local distribution of electric energy. A state or state commission may prohibit an electric utility from selling electric energy to an ultimate consumer in such state if such electric utility or any of its affiliates owns or controls transmission or local distribution facilities and is not itself providing unbundled local distribution service in a state in which such electric utility owns or operates a facility used for the generation of electric energy.
S. 2287 [Clinton]	States retain the ability to opt out of retail competition. States to determine stranded cost recovery. States have clear authority to order retail competition and to impose a charge on the ultimate consumer for receipt of electric energy. States also have authority to impose reciprocity requirements.
Consumer Protection	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Nothing in the Act supersedes existing antitrust laws. No person shall submit or execute a change in the selection of a retail provider except in accordance with verification procedures established by FERC. Nothing precludes a state from establishing additional procedures regarding changes in customer selection in intrastate services. Any person who violates verification procedures is liable to the customer in an amount equal to all charges paid after the violation and to the selected provider in an equal amount. These remedies are in addition to any other remedies available.
H.R. 1230 - DeLay	Nothing in the Act modifies, impairs, or supercedes applicable antitrust acts.
H.R. 1359 - DeFazio	
H.R. 1960 - Markey	Not later than January 1, 1999, the Federal Trade Commission in consultation with the EPA and the Secretary of Energy shall issue rules prescribing the time, form, content, and frequency of supplier disclosure. Disclosure to electric consumers must include historic and projected generating source data, air and water emissions data, specified price information, historic and projected reliability data, and notice of any pending legal actions for noncompliance with applicable laws. Except as otherwise required by law or with prior written affirmative approval of the consumer, any person receiving or obtaining customer information by virtue of providing retail electric service or metering and billing service shall only use, disclose, or permit access to individually identifiable consumer information in its provision of retail electric service. Aggregate information that does not disclose consumer-specific data can be used or disclosed as long as it is available on reasonable and nondiscriminatory terms to all requestors. In order to qualify for a public benefit certification, state laws and regulations must require all persons seeking to provide retail electric service to meet minimum qualifications to protect public safety and welfare and ensure continued reliability of the distribution system.

COMPARISON OF PROPOSED FEDERAL ELECTRIC RESTRUCTURING LEGISLATION (Revised July 1998)	
H. R. 2909 - Pallone	
H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	No specific provision. State allowed to impose requirements to promote the public interest and provide information to consumers.
S. 1401 - Bumpers/Gorton	Beginning on January 1, 2002, FERC shall ensure that each retail electric energy supplier discloses to the public information on types of fuel used to generate electricity sold by the supplier, including the percentage of energy sold by the supplier that is generated by each fuel type.
S. 621 - D'Amato	
S. 687 - Jeffords	Consumers have a right to certain information to make objective choices on their electric service providers. The Secretary of Energy shall establish a disclosure system that enables retail consumers to knowledgeably compare retail electric service offerings, including comparisons based on generation source portfolios, emissions data and price. Not later than March 1, 1999, the secretary in consultation with the board and a federal interagency task force, shall promulgate regulations prescribing the form, content, and frequency of disclosure of emissions and generation data of electricity by generation facilities to electricity wholesalers or retail companies, by wholesalers to retail companies, by retail companies to ultimate consumers and by generation facilities selling directly to ultimate customers. Failure of a retail company to accurately disclose information as required shall be treated as a deceptive act in commerce under Section 5 of the Federal Trade Commission Act.
S. 722 - Thomas	A state may establish and enforce performance standards for the retail sale, marketing or delivery of electric energy to ensure system reliability, protect human health and public safety, and protect retail consumers from unfair business practices.
S. 1276 - Bingaman	
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	The Secretary of Energy is authorized to adopt rules requiring all suppliers of electricity to disclose information on price, terms, and conditions of their offerings, including the type of generation source and generation emissions' characteristics. FERC has jurisdiction over mergers or consolidations of electric utility holding companies and generation-only companies. FERC has power to remedy wholesale market power and, upon petition from the state, to remedy retail market power if the state is unable to sufficiently remedy the market power. A rural safety net can be established, if necessary, to address unintended consequences arising from the transition to retail competition. Nothing in the proposal affects operation of existing anti-trust laws.
Low-Income Assistance/Public Benefits Charges	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	States may impose a charge deemed necessary by the state or the state regulatory authority to fund low-income assistance programs, environmental, renewable energy, conservation programs, or to provide for the retraining of utility employees. Nonregulated utilities may impose similar charges.
H.R. 1230 - DeLay	Nothing in the Act affects authority of state or local government to provide service to residential customers unable to afford electricity, including authority to establish nondiscriminatory local distribution access charge on any power delivered. State and local government retains authority over any specific matter not addressed in the Act including universal service, conservation programs, consumer choice regarding renewable energy, research and development programs, and any other matters deemed appropriate by a state or local government.
H.R. 1359 - DeFazio	The same National Electric System Public Benefits Fund program that funds renewable energy resources is available upon similar terms and conditions for universal and affordable service programs. A program that supports universal and affordable service is any program that promotes high-quality and reliable electric service at just, reasonable, and affordable rates for low-income consumers and those in rural, insular, or high-cost areas.
H.R. 1960 - Markey	One of the criteria for issuance of a state certification of compliance is that the state must have imposed a nonbypassable charge to ensure sustained and equitable allocation of costs associated with low-income services. Within 1 month after enactment FERC shall establish a federal-state board to recommend uniform universal service support mechanisms. Each state shall consider recommendations from the joint board prior to making a certification of competition. Universal service principles are enumerated that include quality service at just, reasonable, and affordable rates, access to advanced electric services should be provided in all regions of the nation, consumers in all regions should have access to services, including advanced services that are reasonably comparable to those offered in urban areas and at rates that are reasonably comparable to urban rates. All providers of electric services should make an equitable and nondiscriminatory contribution to the preservation and advancement of universal service. There should be specific, predictable, and sufficient mechanisms to preserve and advance universal services. States may adopt regulations to preserve and advance universal service.
H. R. 2909 - Pallone	

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H. R. 3927 - English	
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	After December 15, 2003, each retail provider is obligated to sell energy to any state consumer served by the provider if state determines such consumer does not have reasonable access to retail competition. If provider is subject to state authority, state shall set a just and reasonable rate. If provider is nonregulated, provider shall establish appropriate level of compensation. State may impose a nonbypassable universal service charge on distribution and retail transmission customers of all providers to fund such programs. Act does not prohibit state from assessing charges on consumers to fund public benefit programs such as low-income assistance, energy research, or efficiency and conservation.
S. 1401 - Bumpers/Gorton	A state may establish a Universal Service Program that ensures all consumers have access to at least one retail electric supplier at a just and reasonable rate. After January 1, 2002, each retail provider in a state that has not yet established a Universal Service Program is obligated to sell retail energy to, or purchase energy on behalf of, any of its customers in a particular geographic area in which a state regulatory authority or FERC, if the state fails to make a determination, determines that there is not effective retail electric competition in such area and the consumer has not affirmatively chosen a retail electric supplier. Retail provider performing such a service is entitled to a just and reasonable rate from the consumer. The state may impose a nonbypassable Universal Service Charge on all customers of every retail electric provider in the state to fund all or part of the costs of a Universal Service Program. Nothing in the Act prohibits a state from assessing charges on retail consumers of energy to fund public benefits programs such as those designed to aid low-income consumers, promote energy research and development, or energy efficiency and conservation.
S. 621 - D'Amato	
S. 687 - Jeffords	The same National Electric System Public Benefits Fund matching fund program for renewable energy and conservation is available for public purpose programs relating to universal electric service and affordable electric service.
S. 722 - Thomas	The transition to competition should not impair the ability of states to determine recovery of the substantial investments made by electric utilities to serve customers. A state or nonregulated utility may require, as a condition of the purchase by any person or municipality located in the state or service area of the nonregulated utility, as appropriate, of a retail electric supply or local distribution service, the payment of a charge determined by the state or nonregulated utility to further public policy goals including funding assistance to low-income consumers. Nothing in the Act deprives a state of the authority to require all electricity providers that sell electricity to retail customers in the state to assist in providing universal service.
S. 1276 - Bingaman	The Act specifies that it is the sense of Congress that every consumer should have access to electric energy at reasonable and affordable rates and that FERC and the states should ensure that competition does not result in loss of service to rural, residential, or low-income consumers. Any state or state commission that requires an electric utility to provide unbundled, local distribution service shall consider adopting measure to ensure that every consumer has access to electric energy at reasonable and affordable rates and prevent the loss of service to rural, residential, or low-income consumers. Additionally, the state shall report to FERC on any measures adopted hereunder.
S. 1483 - Murkowski	
S. 2182 - Gorton	
S. 2187 - Nickles	
S. 2287 [Clinton]	A $3 billion per year public benefit fund is created to provide matching funds to states for low-income assistance, energy efficiency programs, consumer education, rural assistance and the development and demonstration of emerging technologies, particularly renewables. The fund is administered by a Federal-State Joint Board. As a condition of access to the grid, every owner of a generation facility larger than one megawatt must pay a public benefits charge not to exceed 1 mill/kWh. Every 5 years the fund shall be adjusted for inflation. The fund sunsets in 15 years except for rural assistance programs.
Other	
H.R. 338 - Stearns	
H.R. 655 - Schaefer	Requires states to give utilities flexible pricing and incentive regulation.
H.R. 1230 - DeLay	Within 3 months of enactment, FERC shall report to Congress its plan for implementing the Act including potential obstacles that could inhibit full and reasonably expeditious implementation. Not later than 30 months after enactment, FERC shall conduct an evaluation of the Act and report to Congress on the extent to which rates have been reduced, and the level of reliability, and the extent of competition in electric energy markets.
H.R. 1359 - DeFazio	The National Electric System Public Benefits Board shall be composed of 3 persons who are officers or employees of the United States and four state commissioners nominated by the national organization of the state commissions and appointed by the Secretary of Energy. The secretary shall appoint 1 member of the board to serve as chairman. Within 180 days after enactment, the secretary shall promulgate rules and procedures for the board, including procedures for selecting a non-federal fiscal agent. Within 90 days after promulgation of the secretary's rules, the board shall institute a proceeding to establish regulations governing the public benefits

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	program. Regulations shall include criteria for eligibility of state public service programs.
H.R. 1960 - Markey	FPA is amended to provide for electric reliability councils. An electric reliability council is a self-regulated organization whose membership is composed of electric utilities or transmitting utilities and whose mission is to promote the reliability of electricity supply and the system. Each utility and transmitting utility shall become a member of an electric reliability council. The council shall establish rules to permit open access, assure fair representation, equitably allocate dues and fees and other charges, include standards of utility operation to foster reliability, and provide mechanisms for discipline of violators. FERC shall oversee the operations of the electric reliability councils.
H. R. 2909 - Pallone	Benefits of competition will not be achieved if some competitors enjoy an advantage resulting from externalization of environmental or other costs, permitting them to charge prices for electricity that do not reflect the full economic and environmental cost of production. Allowance programs for certain air pollutants are established. The system of tradable credits includes allowances for entities that have reduced gross electric energy demand during a covered period.
H. R. 3927 - English	Certain provisions of the IRS Code of 1986 are amended in respect to governmentally owned electric utilities. Bonds issued to finance certain governmental electric output facilities would be treated as private activity bonds. Certain exceptions are created for small governmental utilities that furnish electric energy services to less than 5,000 customers and which derive at least 30 percent of their average gross income during any 3-calendar year period from sales to residential consumers. Other exceptions are created for situations where sale of electric energy services is by a governmental utility with a qualified governmental service area to another governmental utility for resale solely to ultimate consumers located within the qualified governmental service area of the purchasing governmental utility. There is also an exception for certain pooling transactions and for existing contracts. With respect to bonds issued on or before the effective date, the term "private business use" does not include use by a persona of a transmission or distribution facility of a governmental utility if the use is part of a comprehensive statewide or regional open-access program mandated or encouraged by a federal or state regulatory entity or results from the turnover of operational control to an ISO.
H. R. 3976 - Tauzin	
H.R. 4183 - Solomon	
S. 237 - Bumpers	Allows Tennessee Valley Authority to sell at retail outside current jurisdictional limits with appropriate approvals.
S. 1401 - Bumpers/Gorton	Title V is reserved to implement provisions of a review of the Bonneville Power Authority (BPA) conducted by the governors of the 4 northwest states. Among the recommendations is the separation of transmission and power marketing functions of BPA, with FERC oversight of access to BPA's transmission system. Additionally, FERC rules on nondiscriminatory, open access to transmission services apply to BPA transmission services except as otherwise provided by FERC. FERC has authority to develop a transition cost recovery mechanism for BPA and to allow BPA to participate in an ISO. BPA is prohibited from marketing, selling, or disposing of electric power to end use or retail customers that did not have a contract with BPA for services to specific facilities as of October 1, 1997. Beginning January 1, 2001, all retail and wholesale electric energy suppliers of the Tennessee Valley Authority shall have the right to sell retail and wholesale electric energy to persons that currently purchase such power from TVA. Beginning the same day, TVA may sell wholesale power outside its current jurisdictional limits, subject to certain restrictions. Beginning on January 1, 2001, any person under contract to TVA may cancel their contract upon 1 year's notice, but will be responsible for retail or wholesale stranded costs as determined by FERC. TVA rates are only effective upon approval by FERC. The board of TVA must prepare a study for selling TVA, except its dams and appurtenant works, to private investors and, not later than 2 years after enactment, the plan must be submitted to Congress. The board may not take action to implement the plan without further authorizing legislation.
S. 621 - D'Amato	
S. 687 - Jeffords	The National Electric System Public Benefits Board shall be composed of 1 FERC representative, determined by FERC; 2 representatives of the Secretary of Energy, appointed by the secretary; 2 persons nominated by the national organization representing state regulatory commissioners, appointed by the secretary; 1 person nominated by the national organization representing state utility consumer advocates, appointed by the secretary; 1 person nominated by the national organization representing state energy offices, appointed by the secretary; 1 person nominated by the national organization representing energy assistance directors, appointed by the secretary; and 1 representative of the environmental protection agency, appointed by the administrator of EPA. Additionally, the Act provides for the establishment of nationwide emissions standards. Not later than July 1, 1999, the EPA administrator shall promulgate final regulations establishing a schedule of limits for each pollutant. The Act also creates a system of tradable emissions credits.
S. 722 - Thomas	A state may provide that any utility in the state may deny local distribution access to any other utility if the seller or an affiliate of the seller is not providing comparable access to any local distribution facility owned, controlled, or operated by the seller or an affiliate.
S. 1276 - Bingaman	
S. 1483 - Murkowski	The Act amends the Internal Revenue Service Code to allow public power entities to participate in certain electrical transactions without losing the tax-exempt status of their bonds. The following transactions do not result in a forfeiture of tax-exempt status: (1) the sale of output by a facility to another state or local government output facility for resale by such other facility if such other facility is not participating in an open-access plan and the output is to be used for government use; (2) participation by such facility in an output exchange agreement

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	with other output facilities if (a) such facility is not a net seller of output under such agreement determined on not more than an annual basis, (b) such agreement does not involve output-type contracts, and (c) the purpose of the agreement is to enable the facilities to satisfy differing peak load demands or to accommodate temporary outages; (3) the sale of excess output by such facility pursuant to a single agreement of not more than 30 days' duration, other than through an output contract with specific purchasers; (4) the sale of excess output by such facility does not exceed $1 million. Public power entities may elect to terminate their tax-exempt bond status for certain future transactions without jeopardizing their existing bonds. The election must be made with respect to all output facilities for the furnishing of electric energy. No bond exempt from tax under Section 103 may be issued on or after the date of the participation by such facilities in an open-access plan with respect to all such facilities. Such outstanding bonds used to finance the facilities must be redeemed not later than 6 months after, in the case of bonds issued before December 1, 1997, the later of the earliest date on which such bonds may be redeemed or the date of election, and, in the case of bonds issued after November 30, 1997, and before the date of the participation by such facility in an open-access plan, the earlier of the earliest date on which such bonds may be redeemed, or, the date which is 10 years after the date of the enactment of the relevant subsection. The effective date of the amendments shall apply to sales of output after November 8, 1997.
S. 2182 - Gorton	Amends Section 141(b)(6) of the IRS Code of 1986 to clarify that open-access transactions do not constitute a private business use. Open-access transactions are defined to include providing open-access transmission services and ancillary services that meet the reciprocity requirements of FERC Order 888 or that are ordered by FERC or that are provided in accordance with a transmission tariff of an ISO approved by FERC or otherwise consistent with state administered laws, rules, or orders providing for open transmission access. A governmental entity covered by the Act may elect to apply the provisions to permitted open-access transactions occurring on or after July 9, 1996.
S. 2187 - Nickles	
S. 2287 [Clinton]	Contains provisions regarding nitrogen oxide trading, nuclear decommissioning costs and a study of the impacts of wholesale and retail competition by the Energy Information Administration.

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(*) Added by the PUCT.