2003

Report to the 78th Texas Legislature

Scope of Competition in Electric Markets in Texas

Public Utility Commission of Texas
January 2003

ACKNOWLEDGEMENTS:

Public Utility Commission of Texas
Rebecca Klein, Chairman
Brett A. Perlman, Commissioner
Julie Caruthers Parsley, Commissioner

Project Leads
Brian Lloyd
Carrie Collier

Project Team
Andrew Blifford
Lauren Clark
Slade Cutter
Letitia Garcia
Richard Greffe
Kristi Hobbs
Tom Hunter
Jennifer Johnson
Nieves Lopez
Robert Manning
Keith Rogas
Jess Totten

Rebecca Klein
Chairman

Brett A. Perlman
Commissioner

Julie Caruthers Parsley
Commissioner

W. Lane Lanford
Executive Director

Public Utility Commission of Texas

January 15, 2003

Honorable Members of the Seventy-Eighth Texas Legislature:

We are pleased to submit our 2003 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act (PURA).

Retail competition for all customers served by investor-owned utilities in the Electric Reliability Council of Texas (ERCOT) began on January 1, 2002 in accordance with Senate Bill 7 (SB 7), which was enacted in 1999. The report describes the activities of the Commission since 2001 to successfully introduce choice to retail electricity customers, as well as an analysis of the savings achieved by customers in the first year of competition.

The Commission's estimates in this report show that retail customers have saved, at a minimum, over $1.5 billion in electricity costs during the first year of competition as compared to the regulated rates in effect during 2001. Additionally, low-income customers have received almost $70 million in discounts through the System Benefit Fund through October 2002.

In all areas open to competition, there are multiple retail electric providers (REPs) offering service to all customer classes, with as many as ten REPs offering service to residential customers in some areas. Customers are continuing to exercise their opportunity to choose an electric provider in increasing numbers.

The Commission has conducted numerous rulemakings, contested cases, and projects in order to provide a clear set of market rules for Texas and has registered market participants. The Commission has administered a customer education campaign to inform customers in Texas about the choices available to them in the new market, including the distribution of over 5 million copies of the *"Power Guide to Electric Choice"* to customers throughout the state. The Commission has also administered a pilot project to test the technical systems needed for retail competition.

The Commission has also worked closely with ERCOT to resolve many of the technical issues related to switching and billing customers in the early months of the market. While work still remains to make the systems more robust and reliable, great progress has been made during 2002 to resolve these issues.

This report describes recent developments in the Texas and national electricity industry and the challenges facing the energy industry. The report also identifies several areas where the Commission believes it appropriate for the Legislature to expand or clarify the authority of the Commission, especially with respect to its oversight of the electric industry in Texas.

We look forward to continuing to work with you on this and other policy objectives. If you need additional information about any issues addressed in the report, please call on us.

Sincerely,

Rebecca Klein	Brett A. Perlman	Julie Caruthers Parsley
Chairman	Commissioner	Commissioner

TABLE OF CONTENTS

APPENDICES

1. **LIST OF ACRONYMS AND GLOSSARY**
2. **LIST OF RULEMAKING PROJECTS**
3. **LANDOWNER PARTICIPATION IN TRANSMISSION LINE PROCEEDINGS BROCHURE**
4. **LIST OF RETAIL ELECTRIC PROVIDERS**
5. **ELECTRONIC DATA TRANSACTIONS LIST**
6. **FUEL CELL WHITE PAPER**
7. **LIST OF NEW GENERATION PROJECTS: COMPLETED, DELAYED AND CANCELLED**

INDEX OF TABLES

INDEX OF FIGURES

I. INTRODUCTION AND SUMMARY

On January 1, 2002, retail competition in the electric market began for all customers of investor-owned utilities in the Electric Reliability Council of Texas (ERCOT) region. The new market structure envisioned by Senate Bill 7[1] dramatically altered the provision of electricity to most retail customers in Texas.

Prior to the introduction of retail electric competition in ERCOT, all retail customers were served by investor-owned electric utilities, electric cooperatives (co-ops), or municipally owned utilities (MOUs), and very few customers had a choice of companies to supply their power. The Public Utility Commission of Texas (PUC or Commission) certificated the service areas of utilities, co-ops, and MOUs, which, for the most part, had an exclusive right and obligation to serve customers in that service area. The investor-owned utilities, MOUs, and co-ops built and operated generation plants and transmission and distribution facilities, and performed retail functions such as customer service, billing, and collection. The Commission set electric rates for those utilities over which it had ratemaking authority. The objective of such ratemaking was to provide utilities an opportunity to earn a reasonable rate of return on prudent investments and to recover reasonably incurred expenses, while also ensuring just and reasonable rates for retail customers.

SB 7 established a framework to allow retail electric customers of investor-owned utilities to select their provider of electricity beginning January 1, 2002. The governing boards of co-ops and MOUs were granted the authority to decide if and when to open their service areas to retail competition.

The distribution of electricity is still the right and obligation of the certificated utility, but the customers in investor-owned-electric utility service areas within the ERCOT region now have the option of selecting their power provider. Although transmission and distribution facilities remain regulated by the Commission, the prices for the production and sale of electricity to both wholesale and retail customers are predominantly dictated by market forces instead of a government rate-setting process. Customers with a peak demand of one megawatt (MW) or less continue to have a regulated "price-to-beat" rate available until 2007, and the Commission is required to designate "providers of last resort" (POLRs) to ensure that all customers have access to electricity in areas open to competition. Other retail prices are no longer subject to Commission regulation or oversight, and customers are free to choose among the variety of options available from competitors in the marketplace. Section II of this report provides an overview of the new market structure under SB 7.

The opening of the retail market followed three years of intensive effort by the Commission, consumer advocates, utilities, retail electric providers, power generation

[1] Act of May 27, 1999, 76th Leg., R.S., ch. 405, 1999 Tex. Gen. Laws 2543 (codified primarily at TEX. UTIL. CODE ANN., ch. 39, 40, and 41) (SB 7).

companies, and others to create the market rules and institutions needed to support competition. The Commission projects to implement competition included:

- Forty-one rulemakings to provide further detail to the market structure outlined by SB 7;
- Nine contested cases to approve the business plans for separating the business activities of formerly integrated utilities into unregulated power generation companies (PGCs), regulated transmission and distribution utilities (TDUs), and retail electric providers (REPs);
- Nine contested cases to set the rates for transmission and distribution service, stranded cost charges, and the system benefit fund fee;
- Twelve contested cases related to the setting of price-to-beat rates for the REPs affiliated with the local TDU;
- Contested proceedings related to the approval and enforcement of the wholesale market rules and customer registration and switching procedures adopted by the ERCOT Independent System Operator;
- Two contested proceedings to evaluate the readiness of the areas of Texas outside of ERCOT for retail competition;
- Fifty-five proceedings to certificate REPs;
- One hundred thirty one proceedings to register aggregators;
- A pilot project to evaluate the readiness of the market to implement customer choice, including testing the systems needed to support retail competition;
- Administration of a statewide customer education campaign to inform retail customers about choices in the new competitive market; and
- Administration of the system benefit fund.

Companies in the electric business have made significant investments in Texas in recent years. Forty-seven new generation plants were installed in Texas between January 1999 and August 2002, leading to reserve margins in excess of 35% for 2002. A significant amount of new transmission investment has also been undertaken to ensure that the transmission grid can accommodate the power flows needed to facilitate retail and wholesale competition. Retail providers, transmission and distribution utilities, and ERCOT have also invested millions of dollars in the computer systems that permit them to operate in the new competitive environment.

Retail competition for utilities in the non-ERCOT regions of Texas has been delayed, either by the Legislature (in the case of the Panhandle and El Paso), or the Commission (in the case of east Texas). The Commission delayed competition for the Entergy and Southwestern Electric Power Company (SWEPCO) service areas in east Texas due to a lack of participation by REPs in these markets, and a lack of market rules and infrastructure needed to support full and fair retail competition for all customer classes. The Commission continues to work to develop the needed market rules to encourage REPs to enter these markets.

In the ERCOT region, the combination of excess generation capacity, lower natural gas prices, and implementation of the price-to-beat rate reduction mandated by SB 7 has led to retail customers in Texas paying significantly less for electricity in 2002 as compared to the regulated rates in effect in 2001. Residential customers have saved approximately $900 million on electric bills in 2002 as compared to 2001.

Table 1: Residential Price-to-Beat Savings in 2002

TDU	Residential Price-to-Beat Savings 2002
Oncor	$390 million
CenterPoint	$386 million
CPL	$68 million
TNMP	$44 million
WTU	$14 million
TOTAL	**$902 million**

SOURCE: Texas PUC Electric Division Monthly Bill Comparison Surveys—http://www.puc.state.tx.us/electric/rates/RESbill.cfm

The Commission has also successfully implemented the low-income discount programs mandated by SB 7. Low-income residential customers have received an additional $68 million in discounts from the price to beat or competitive offers under this program through the end of October 2002, or a total average savings of $136 per customer through October 2002.

As of December 2002, competing REPs were offering up to 14% in additional savings off the price to beat to residential customers. A household using an average of 1,000 kWh per month can save as much as $166 a year by switching to the lowest competitive offer in some areas. At December 2002 price offerings, residential customers could save, in total, up to an additional $636 million (on an annual basis) if *all customers* were to switch to the lowest cost provider in their area. At this early stage in the retail market, competitive forces appear to be working to reduce the electricity rates paid by consumers in Texas.

Table 2: Additional Annual Residential Savings Available from Lowest Competitive Offer

% Switched	Additional Annual Savings Available
5%	$32 million
10%	$64 million
15%	$95 million
20%	$127 million
25%	$159 million
100%	**$636 million**

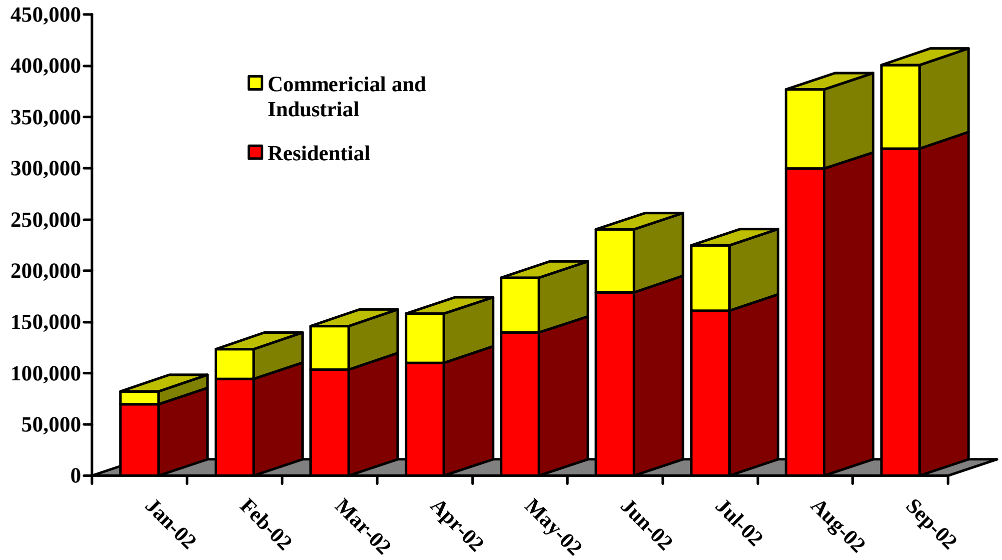
SOURCE: Competitive Residential Offers from the Texas Electric Choice website—http://www.powertochoose.org/yourchoice/yourchoiceframe.html

Commercial and industrial customers have also seen significant savings. They have paid approximately $645 million less in 2002, compared to 2001 bills. Many of these customers, especially cities and other government entities have achieved these savings through successfully aggregating with other customers.

As of December 2002, residential customers had at least three choices of REPs, and in some service areas, had a choice of ten different providers, and even more product offerings, including renewable, or "green," power.

Customers in all customer classes have taken advantage of the opportunities to switch providers. As of September 2002, over 400,000 retail customers were taking service from REPs not affiliated with their local transmission and distribution utility (TDU). The chart below shows the cumulative number of customers who have switched to other retailers, by month.

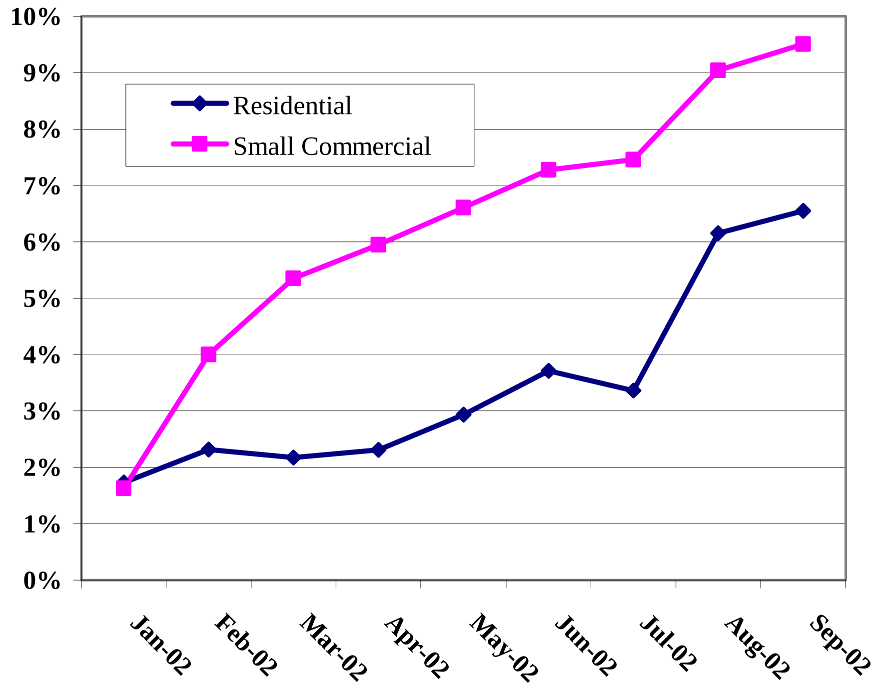
Figure 1: Number of Customers Served by a Competitive REP in ERCOT (2002)



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

The majority of these customers are residential customers, and as of September 2002, more than 6% of all residential customers were served by a non-affiliated REP. As shown in the following chart, there has been a steady increase in the number of residential and small commercial customers served by competitive REPs.

Figure 2: Percentage of Residential and Small Commercial Customers Served by a Competitive REP (2002)



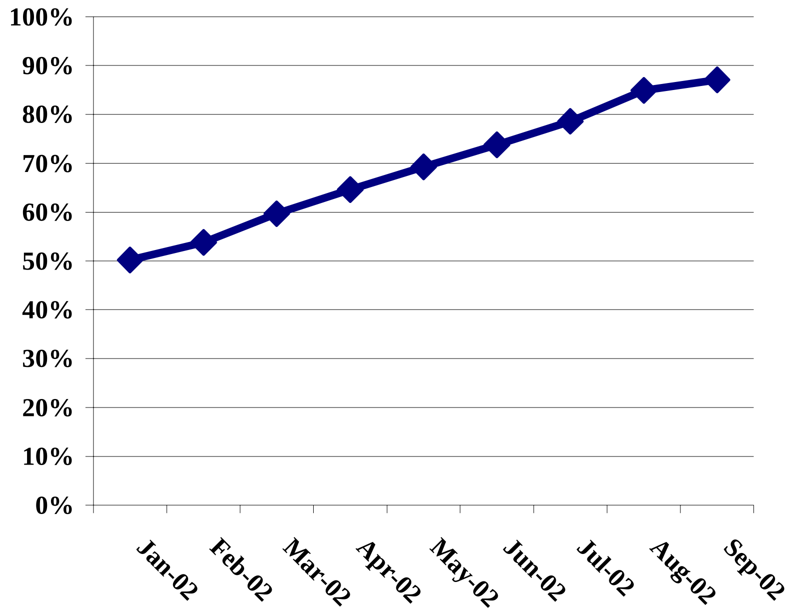
SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

While commercial and industrial customers make up a smaller percentage of total customers who have switched, these customers have switched in much greater proportion within their customer class, with over 9% of small commercial, and over 16% of larger commercial and industrial customers receiving service from a non-affiliated REP in September 2002.

As discussed further in Section IV of this report, many of the commercial and industrial customers who have switched are larger customers, so that up to 40% of megawatt-hour (MWh) sales to these customers were sold by non-affiliated REPs in some service areas.

For customers without a price to beat available from the affiliated REP, both the competitive REPs and the affiliated REPs can offer competitive rates. The Commission required affiliated REPs to give non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002 if they did not negotiate other arrangements with the affiliated REP or switch to a competitive REP. As of September 2002, over 85% of these customers have negotiated a competitive contract with a REP. Because these customers typically use large amounts of energy, there is a clear economic incentive for these customers to fully explore their options in the competitive market.

Figure 1: Percentage of Non-Price-to-Beat Customers with a Competitive Contract (2002)



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from Affiliated REPs.

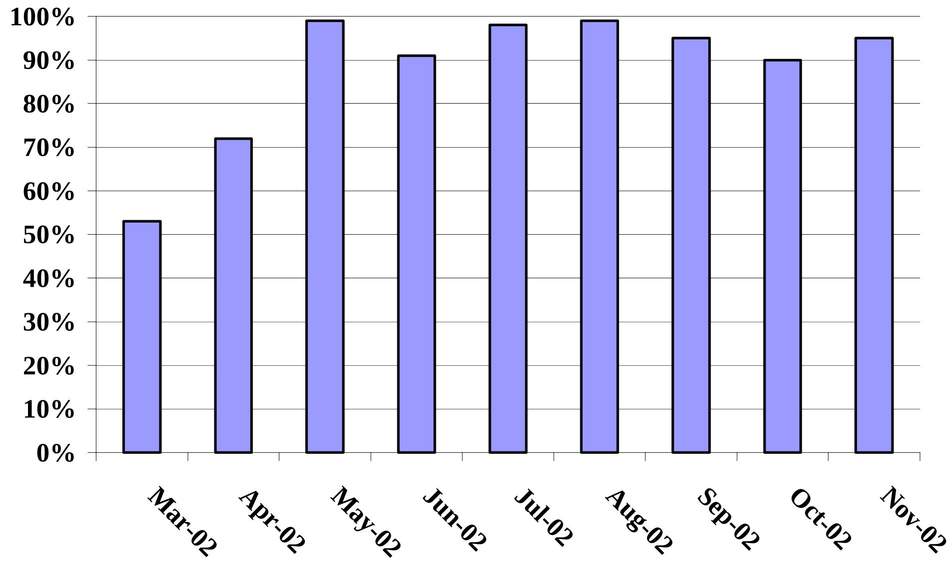
While customers have taken advantage of the opportunity to shop for electricity, many of them have experienced significant problems in switching to a different REP and in getting accurate electric bills from their REP.

In order to effectuate a switch to a new provider, a series of transactions between the new REP, ERCOT, and the TDU, is needed to transfer the service of the customer to the new REP. The computer systems and electronic transactions needed to accomplish this task were initially unsuccessful in processing switch transactions for a significant number of requests. As a result, switches were not processed in accordance with the timelines detailed in the ERCOT Protocols and Commission rules, resulting in delayed or missing switch requests.

Market participants and the Commission have expended considerable effort and resources to resolve these problems, and as a result, success in switching customers has improved dramatically since the beginning of the year.

The following chart shows the trend in switching success for various time periods during 2002. This analysis has been prepared from sample data and may not represent the experience of specific REPs in the market. The Commission believes it is, however, a fair representation as to the state of the market systems.

Figure 2: Percentage of Switches Completed Successfully, March - November 2002

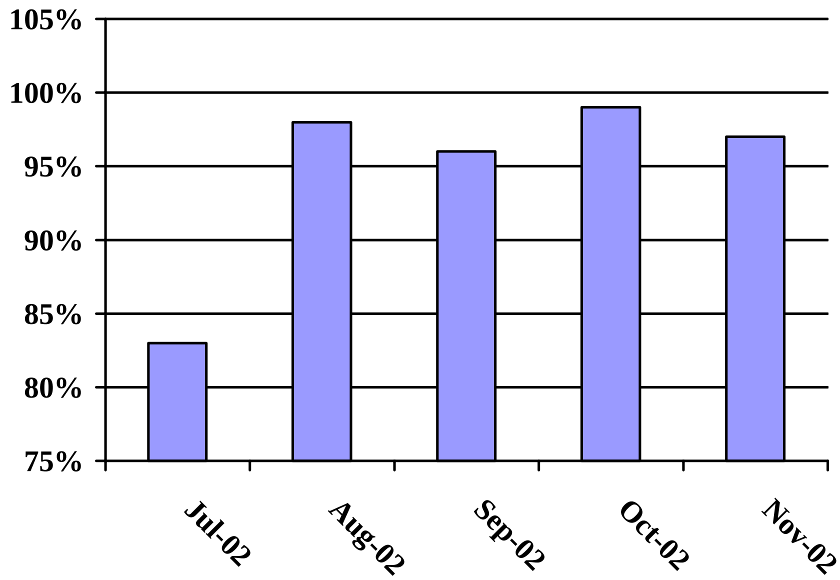


SOURCE: Data Responses filed in Project No. 24462.

Early in 2002, numerous retail customers reported difficulties in establishing service when they moved to new residences. These “move-in” transactions were not fully tested during the pilot project, and early experience in the market demonstrated that the existing systems and procedures were inadequate to perform these requests in a timely manner.

In response to these difficulties, TDUs established manual procedures to ensure that customers moving in would not have an unreasonable delay in getting electric service. As a result of these procedures, retail customers are receiving service in a much more timely fashion than they were at the beginning of 2002. ERCOT currently has a task force working to address the systemic operational issues related to move-ins and move-outs, and significant system changes are expected. Nevertheless, the vast majority of customers are being moved in on a timely basis. The following chart illustrates the improvement in performance that has occurred since July 2002, when the Commission began receiving data related to move-in requests.

Figure 3: Percentage of Move-Ins Completed Successfully, July-November 2002



SOURCE: Data Responses filed in Project No. 24462.

REPs also experienced difficulty in billing retail customers during the early months of retail competition, in part due to REPs not receiving meter reading information in a timely manner from ERCOT and the TDUs.

The REPs' inability to issue accurate bills has a significant impact on retail customers when the customer's REP is unable to issue a bill (or bills) to the customer for several months. Commission rules require that if a REP bills for multiple months of charges, that REP must give the customer the same number months to pay as the number of months included on the multiple-month bill. (*i.e.*, if a bill includes three months of charges, the customer has three months to pay the bill in its entirety). Billing performance has improved dramatically in recent months, and by November 2002, most customers were receiving bills on a timely basis. Several REPs have continued to lag in issuing timely bills, and the Commission is working with these companies to improve their performance.

Many of the technical problems that arose in the early days of the marketplace have been remedied through manual intervention in processes that are designed to be automated. As a result, market participants are incurring increased costs related to these processes. Ultimately, many of these problems will be resolved by redesigning systems or processes, which may involve significant additional costs to TDUs, REPs, and ERCOT.

Beyond the technical issues related to switching and billing retail customers, the Commission is exploring a number of issues to ensure that retail competition continues to be beneficial to customers in Texas. Among these issues are:

- **Difficult financial conditions in the energy market, including reduced investor confidence in merchant generation companies and retail electric providers.** This issue includes the treatment of retail customers if a REP files for bankruptcy protection. The depressed state of the energy industry is also an important element in considering market reforms, particularly any reforms that would call for market participants to make significant investments in new systems in Texas.

- **The potential impact on retail competition of the stranded cost true-up proceedings**. Utilities are required to finalize their stranded cost determination in 2004 through market valuation of assets. Due to the current level of uncertainty and the lack of investor interest in wholesale generation companies, it is possible that the market-based valuations of generation facilities or companies that own them will result in significant stranded costs for several companies. High stranded costs would, in turn, likely result in higher delivery charges from the TDUs.

- **Generation capacity adequacy.** While a significant amount of new generation capacity has been added in the state since the wholesale market became competitive in 1995, events in the national energy markets have slowed development and construction of new generation in all parts of the country. More than 9,700 MW of announced new generation capacity planned for Texas have been delayed and more than 4,400 MW have been cancelled. Additionally, American Electric Power (AEP) and CenterPoint Energy (CenterPoint) announced in fall 2002 that they plan to mothball, collectively, 7,000 MW of older, less-efficient generating capacity, which will reduce projected ERCOT reserve margins. The Commission has opened a rulemaking project to determine whether the adequacy of reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin.

- **Municipal Registration of Retail Electric Providers.** PURA § 39.358 permits a municipality to require REPs serving residents of the municipality to register with and pay an administrative fee to the municipality, and permits the municipality to suspend or revoke a REP's registration.[2] Several of the ordinances that have been approved would result in a dramatic increase in REPs' operating costs in the cities, and could reduce competition in those cities. In December 2002, the Commission adopted a rule that provides an optional "safe-harbor" process for municipal registration of REPs. The rule is intended to simplify and provide certainty to the registration process.

- **Transmission Constraints.** Although significant amount of new transmission investment has been installed in Texas since 1999 in order to accommodate the power transactions related to retail competition, significant transmission constraints limit the deliverability of some generation resources, especially wind power from West Texas. Texas is nearly three years ahead of schedule with respect to meeting the Legislature's

---

[2] Public Utility Regulatory Act, TEX. UTIL CODE ANN. §§ 11.001-64.158 (Vernon 1998 & Supp. 2003) (PURA)

mandate to increase renewable generation capacity. Nearly all of this progress is attributable to new wind power in West Texas. However, so much wind power has been added that the existing transmission system is not always capable of delivering all of the power available from the wind projects. Transmission projects are planned to relieve the bottlenecks, but significant new facilities are required, which will take up to five years to complete. The Commission is currently reviewing these issues and exploring potential solutions.

- **Wholesale Market Transparency.** The ERCOT wholesale market is primarily a bilateral market, in which buyers and sellers of power negotiate contracts for electricity on whatever terms they choose. ERCOT operates spot markets that are designed to procure small amounts of power to ensure that the production and consumption of power are always in balance. The Commission is re-examining the design of the ERCOT market for several reasons. A broader market could provide greater liquidity and price transparency, and provide better information about the market's perception of future supply and demand conditions. The existing market design also presents gaming opportunities for market participants that could probably be eliminated by redesigning the market. Finally, the Federal Energy Regulatory Commission (FERC) has proposed a standard wholesale market design (SMD) for rest of the United States, and there may be advantages to Texas in adopting a market design compatible with the SMD for the ERCOT market.

The Commission does not recommend any changes or additions to PURA that would alter the fundamental framework for the transition to competition established by the Legislature in SB 7. The Commission does recommend changes to PURA to increase the ability of the Commission to enforce the law and the market rules developed to implement SB 7. The Commission also recommends a change to the Gas Utility Regulatory Act to enhance competition in the electric market, and several changes to PURA to address competitive metering and the construction of new transmission investment. The Commission has also identified a number of clarifications that could be addressed should the Legislature choose to do so.

II. OVERVIEW OF THE SENATE BILL 7 MARKET STRUCTURE

Senate Bill 7 dramatically altered the production and sale of electricity to retail customers in the state of Texas. Prior to SB 7, all retail customers were served by integrated investor-owned electric utilities, electric cooperatives (co-ops), or municipally owned utilities (MOUs). The Public Utility Commission of Texas (Commission) certificated the service areas of utilities, co-ops, and MOUs, where, for the most part, these entities were granted the exclusive right and obligation to service customers in an area (except for certain areas that were certificated to more than one utility, co-op, or MOU).

Integrated utilities, MOUs, and co-ops built generation plants and constructed transmission and distribution facilities and performed retail functions such as billing and customer service to meet their obligations to serve. The Commission set electric rates for those utilities over which it had ratemaking authority that gave utilities the opportunity to earn a reasonable return on prudent investments and to recover reasonably incurred expenses, but that were also just and reasonable to retail customers.

To maintain the reliability of the electrical network, the amount of generation produced by generators must match the amount consumed by retail customers, within strict tolerances. Under traditional regulation, the major utilities, MOUs and co-ops in the state maintained their own “control areas” and managed the flow of electricity within their region such that reliability was maintained. Utilities, MOUs, and co-ops were also generally the only entities permitted to build the generation plants needed to serve retail customers.

The wholesale electric market was opened to competition as a result of the amendments to the PURA adopted by the Legislature in 1995. As a part of these amendments, independent power producers (IPPs) were permitted to construct generation facilities and were granted access to the transmission lines of utilities, co-ops, and MOUs in order for IPPs and power marketers to move power to wholesale customers.

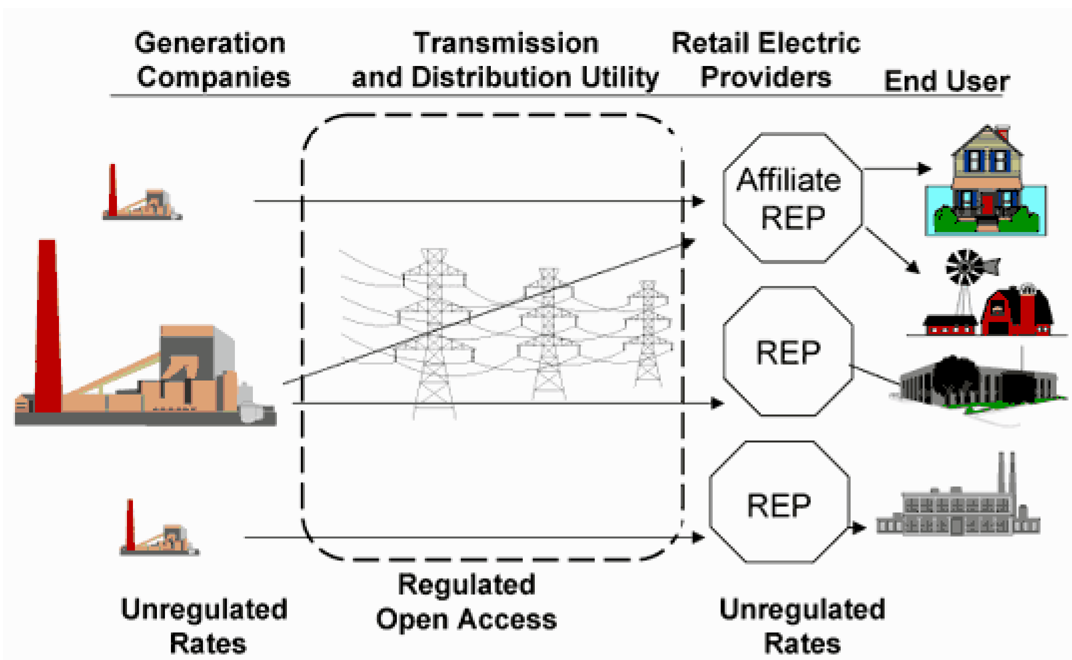
SB 7, adopted by the Legislature and signed into law by Governor George W. Bush in 1999, established a framework to allow retail electric customers to select a provider of electricity other than the traditional utility beginning in January 1, 2002, unless the Commission delayed competition for a utility’s service area. The governing boards of co-ops and MOUs were granted the authority to decide if and when to open their service areas to customer choice.

Although transmission and distribution facilities remain regulated by the Commission, the prices for the production and sale of electricity to both wholesale and retail customers are now predominantly dictated by market forces instead of regulatory rate-setting procedures. Customers with peak demand of one megawatt (MW) or less will continue to have a regulated price to beat available until 2007, and the Commission is required to designate “providers of last resort” (POLRs) to ensure that all customers have access to electricity in the competitive market.

All other retail prices in the marketplace are not subject to Commission regulation or oversight, and customers are free to choose among the variety of options in the marketplace.

SB 7 established a framework for retail competition that is different from that adopted in other states. Formerly integrated investor-owned utilities were required to separate their business functions into three distinct companies: a power generation company (PGC), a transmission and distribution utility (TDU), and a retail electric provider (REP). PGCs operate as wholesale providers of generation services, in the same manner as independent generators. REPs operate as retail providers of electricity and energy services, and are the entities that have the primary contact with retail customers in the new market. TDUs remain regulated by the Commission, and are required to provide non-discriminatory access to the transmission and distribution grid at rates and terms of access prescribed by the Commission. The diagram below illustrates the competitive electric market in Texas.

Figure 4: The Texas Competitive Electric Market



Equal and non-discriminatory access to the transmission grid to all wholesale and retail providers is vital to the success of both wholesale and retail competition. SB 7 required that "independent organizations" ensure equal and open access to the grid. The Electric Reliability Council of Texas (ERCOT) was designated as the independent organization for the majority of Texas. Because ERCOT is entirely with the state boundaries of Texas, ERCOT falls exclusively under the Commission's jurisdiction, and the production and sale of electricity is not subject to regulation by the Federal Energy Regulatory Commission (FERC). For areas outside of ERCOT, FERC is the primary regulatory authority for the independent organization. As will be discussed in greater detail in Section III.D of this report, the development of independent organizations and market rules outside of ERCOT has lagged behind that in ERCOT, and as a result, the Commission found it necessary to delay full retail competition for these areas.

It is noteworthy that, in Texas, ERCOT performs functions in the retail market that are performed by the TDUs in other states that have introduced retail competition. Key elements in the design of the ERCOT retail market are the creation of a single, large retail market throughout the region and the use of a neutral third party to perform tasks related to the scheduling of power and settlement functions. ERCOT also serves as the registration agent for all retail transactions. All customer switch requests, move-in and move-out requests, and monthly electricity usage data flow through ERCOT. In addition, ERCOT performs key tasks such as load profiling. It is expected that standardization efforts such as the ERCOT Protocols and the Commission's pro-forma tariff for transmission and distribution service will result in lower barriers for REPs entering the Texas market, especially in service areas that would otherwise be small markets. Having ERCOT, rather than each TDU, perform these functions should minimize the possibility for bias in the wholesale settlement process and in switching customers from one REP to another.

ERCOT also now has the responsibility of managing the flow of electricity such that reliability is maintained across the network. To perform this task, ERCOT manages and operates markets in which generators bid to provide the services needed to ensure that supply and demand balances in real time.

REPs generally provide electricity to customers by purchasing wholesale electricity from generators located within the ERCOT region. REPs use a Qualified Scheduling Entity (QSE) to schedule power through ERCOT to meet their customers' daily energy needs. All schedules and transactions within ERCOT "flow." This means that schedules are not contingent upon a determination that there is adequate transmission capacity available to move power from the generation resource to the load. If all of the schedules submitted for a particular day or hour cannot be accommodated because of transmission constraints, ERCOT uses a market-based congestion management system to clear the congestion and maintain reliability. The costs associated with clearing the congestion are assigned to market participants under methods outlined in the ERCOT Protocols and approved by the Commission.

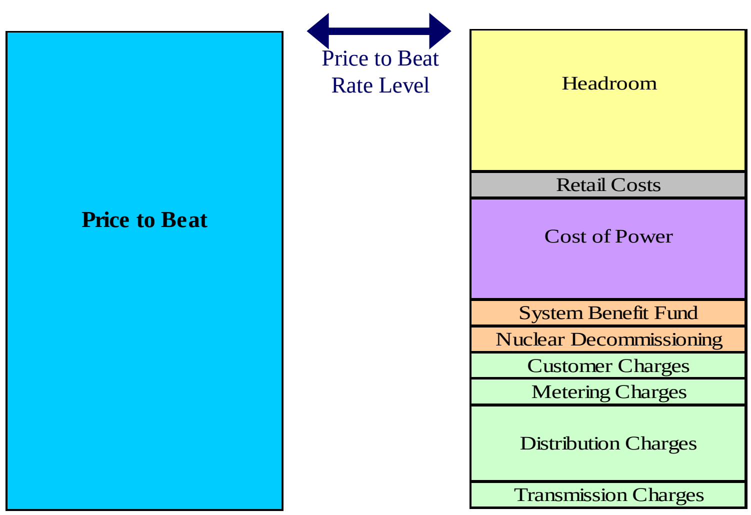
Retail competition has not developed in other parts of the country where the remaining regulated prices are frozen at levels that are below market prices. As discussed in the Commission's 2001 *Report on the Scope of Competition in Electric Markets* to the 77th Legislature, California created a framework for retail competition whereby the regulated retail prices became significantly divorced from wholesale prices. As a result, few retail providers were able to sustain a competitive business in the state, leading to very few choices for retail customers.

Additionally, the incumbent utilities in California were required to provide service to retail customers at rates that were far below their actual costs to serve customers. This constraint lead to tremendous financial difficulties for the utilities, and caused the two largest utilities to be unable to secure power supplies. One utility ultimately filed for bankruptcy protection. Consequently, the state of California had to step in to acquire power supplies for the incumbent utilities, at a significant cost to the taxpayers of that state.

In contrast to the fixed-price regimes established in other states, SB 7 created a framework whereby the remaining regulated rates charged by the affiliated REPs were reduced from 1999 levels, but can be adjusted to reflect changes in the market prices of natural gas and purchased energy. This price-to-beat concept is perhaps the single most important provision of SB 7 with respect to the development of the competitive retail market for residential and small commercial customers. If the price to beat charged by the affiliated REPs is a below market rate, other REPs will be unable to compete for customers, and competition will not develop.

In most areas of the state that are open to competition, these price-to-beat rates charged by affiliated REPs provide a 6% reduction from January 1999 rates, adjusted for changes in fuel costs. These rates appear to have remained above market rates, permitting other competitive REPs to enter the market and profitably serve retail customers. Generally, REPs must be able to price at a level sufficient to recover expenses associated with paying for transmission and distribution service, wholesale generation costs, and costs related to operating a retail business, and still be able to offer price savings sufficient to induce retail customers to switch suppliers. This difference between the price to beat and the costs incurred by non-affiliated REPs is referred to as "headroom," as it defines the range of prices in which non-affiliated REPs can profitably price their services and still entice customers to switch by providing a discount off the price to beat.

Figure 5: Available Headroom—Price to Beat vs. Competitive Rates



III. SUMMARY OF COMMISSION ACTION FROM 2001 TO 2003 TO REFLECT CHANGES IN THE SCOPE OF COMPETITION IN THE ELECTRIC INDUSTRY

The continued development of rules and infrastructure for a competitive retail electric market in Texas has occurred on multiple tracks:

- The Commission's development of rules to implement Senate Bill 7, and revisions to previously adopted rules to address unforeseen circumstances. The Commission uses rulemaking procedures required by the Administrative Procedure Act (APA),[3] and in most cases, uses additional means to enhance public participation;

- The approval of rates for electric delivery service and unbundling plans for the formerly integrated electric utilities through contested cases at the Commission and the State Office of Administrative Hearings (SOAH);

- The approval of price-to-beat rates and adjustments to the price-to-beat fuel factors pursuant to PURA § 39.202 through contested cases at the Commission and SOAH;

- The approval of providers of last resort (POLR) and the associated rates for service to all customer classes through competitive bidding processes, contested cases, and a lottery at the Commission;

- The development of and revisions to market rules and governance structure of the ERCOT independent system operator (ISO) through consensus-based procedures involving stakeholders from all sectors of the industry, and review, approval, modification, and oversight of those rules by the Commission;

- Certification of REPs and registration of aggregators;

- The delay of full retail competition in non-ERCOT areas of Texas, and the continuing development of market rules and independent organizations for those areas through a collaborative process and contested cases at the Commission;

- Administration of a statewide customer education campaign to inform retail customers about choices in the new competitive market;

- Administration of a pilot program beginning in June of 2001 to test the computer systems (including the systems necessary to switch retail customers) needed for retail competition; and

- Administration of the System Benefit Fund.

[3] Administrative Procedure Act, TEX. GOV'T CODE ANN. §§ 2001.001-.902 (Vernon 2000 & Supp. 2003) (APA)

A. RULEMAKING ACTIVITIES

During 2001 and 2002, the Commission continued the work that began shortly after Governor George W. Bush signed SB 7 into law in June 1999. The law explicitly required the implementation of a number of rules, and the Commission adopted additional rules that were necessary to provide details and certainty for companies considering whether to enter the Texas market, as well as for customers considering whether to switch suppliers. Several major rulemakings were initiated and/or completed in 2001 and 2002, and other rules were revised in order to address changes found necessary after observing the operation of the rules in the market. In all, the Commission has completed 41 rulemaking projects related to SB 7. A summary of those rulemaking projects, including dates completed, is included in Appendix 2.

The APA prescribes a process for adopting new rules or amending existing rules that requires an agency to publish a proposed rule in the *Texas Register* for public comments, consider the comments it receives, and then adopt a rule with reasoned justification for its adoption and a response to public comments. In most of the rulemakings to implement SB 7, the Commission has provided significant additional opportunities for interested persons to exchange views and suggestions through the solicitation of written comments and public workshops prior to the development of the proposed rule. While this process often takes a longer time than the standard APA procedures, the additional opportunities for interested persons to participate in the development of rules has resulted in more fully vetted proposed rules and increased confidence in the rules by those who will have to comply with them.

1. Adoption of Major New Commission Rules

a. Price to Beat

As discussed in Section II. Overview of the Senate Bill 7 Market Structure, the price to beat is one of the key components of SB 7. The Commission adopted new P.U.C. SUBST. R. 25.41, relating to *Price to Beat* to implement this provision.[4] The rule generally requires a 6% reduction from the rates in effect on January 1, 1999 for residential and small commercial customers (peak demand of 1 MW or less), with adjustments for the setting of a final fuel factor for the integrated utility as of December 31, 2001. The reduction applies to customers who choose to take service from the affiliated retail electric provider. Affiliated REPs are required to sell electricity at the price to beat until January 1, 2007.

Affiliated REPs cannot require customers to sign long-term contracts as a condition of taking service under the price to beat. Affiliated REPs can offer rates lower than the price to beat beginning January 1, 2005, or earlier if at least 40% of residential or small-commercial customers (1 MW of peak demand or less) move to competitors.

[4] *Rulemaking Relating to Price to Beat,* Project No. 21409, Order Adopting New § 25.41 (Mar. 21, 2001).

The adopted rule also promotes competition by allowing the fuel portion of the rate to be adjusted for changes in the market price of fuel and purchased energy. If the market price of natural gas futures changes by more than 4%, the rule permits the affiliated REP to request adjustments to the fuel factor. The affiliated REP may also request an adjustment to the price to beat if headroom diminishes due to changes in the market price of purchased power as measured by one-year and three-year contract prices.

The mechanism for adjusting the fuel factor portion of the price to beat was among the most controversial aspects of the rule. Several parties argued that the costs and revenues of the affiliated REP should be reconciled for prudency in a manner similar to traditional fuel reconciliation cases for bundled utilities. Other parties argued that the rule should mandate and guarantee a certain level of headroom, even if it resulted in an overall reduction to the 6% discount.

Ultimately, the Commission found that the initial price-to-beat fuel factor should be set by forecasting the costs of the various fuels that the integrated utility used to generate electricity, generally in the same manner as under regulation. The Commission also found, however, that if the price-to-beat fuel factors were not adjusted to fully reflect changes in the market price of electricity, the development of a robust, competitive retail market would be at risk, as the price to beat could fall below the costs of new REPs entering the marketplace.

Additionally, all retail electric providers, including both affiliated and non-affiliated REPs, must purchase their generation needs from the competitive market, and as such, face power prices that are largely influenced by natural gas. Therefore, the Commission found that it was appropriate to allow adjustments to the entire fuel factors due to changes in natural gas and purchased energy, and not solely the portion of the factor that was historically related to gas.

Reliant Resources, Inc. appealed the price-to-beat rule on several bases including that it did not require a minimum level of "headroom" in the setting of the initial price-to-beat fuel factors. The Travis County Court of Appeals upheld the Commission's rule, finding that the Commission had the ability to guarantee an initial amount of headroom to further the Legislature's goals of retail competition but was not required to do so.[5]

As discussed in Section IV.A of this report, it appears that there is adequate headroom under the price to beat, as competitive REPs have been able to offer rates below the price to beat in all portions of the state open to retail competition areas for all customer classes. The Commission is also in the process of considering amendments to the price-to-beat rule, as discussed later in this section.

---

[5] *Reliant Energy, Inc. v. Public Utility Comm'n of Texas*, 62 S.W..3d 833 (Tex. App.—Austin 2001)

b. True-Up Proceeding

In December 2001, the Commission adopted a rule to establish the procedures by which formerly integrated utilities will conduct their true-up proceedings in 2004.[6] The primary purpose of the true-up proceedings is to reach a final determination of the utilities' stranded costs (the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market).

The new rule establishes the process for quantifying the stranded costs of the utilities, and the reconciliation of that amount with prior estimates used to set rates. The rule also provides for reconciliation between differences in the price of power obtained through the capacity auctions and the power costs used in the excess cost over market (ECOM) model, as well as recovery of the final fuel balances of the utilities. Finally, the rule contains provisions related to the treatment of the excess revenues paid by customers for price-to-beat service.

Several investor-owned utilities have appealed the true-up rule, arguing that it:

- Violates the statute by allowing for the possibility of the return of negative stranded costs to ratepayers. The companies argue that this occurs as a result of the rule's netting of various components of the true-up process against the difference between the book value and market value of a company's generation assets.
- Violates the statute by effectively allowing the Commission to increase the control premium that may be added under certain circumstances to the value of a company's equity by more than the 10% permitted by statute.
- Improperly allows the Commission to adjust the book value of a company's assets if the Commission determines that the company has failed to properly mitigate stranded costs.

c. Transmission Access Rules

The Commission revised its transmission access rules in order to accommodate the new market structure in ERCOT.[7] The rule amendments include the establishment of a "transmission cost recovery factor," or TCRF, that permits a utility to receive expedited cost recovery of additional transmission investments, and reflect those costs in the non-bypassable rates that are charged to REPs and, ultimately, retail customers. A TCRF can only recover the capital costs associated with new investments in transmission facilities, and is subject to reconciliation in the transmission utility's next transmission rate case.

The Commission believes that the TCRF mechanism will encourage the timely construction of new transmission facilities needed to facilitate competition by reducing the risk to the transmission utility of making such investments.

---

[6] *Rulemaking Concerning True-Up Proceeding Under PURA § 39.262*, Project No. 23571, Order Adopting New § 25.263 (Dec. 4, 2001).

[7] *Rulemaking Proceeding to Revise PUC Transmission Rules Consistent with the New ERCOT Market Design*, Project No. 23157, Order Adopting New and Amended Transmission Rules and Repealing Certain Rules Consistent with the New ERCOT Market Design (May 25, 2001).

d. Terms and Conditions of Distribution Access

In 2001, the Commission adopted standardized tariffs for electric delivery service that provide a consistent set of rules statewide, regardless of whether a REP is operating in Houston, Dallas-Ft. Worth, South Texas or West Texas. The standardized tariffs are intended to reduce a REP's costs of entry into the market. The tariffs were developed through a project that included a rulemaking for investor-owned TDU distribution service, and a rulemaking for municipally owned utilities (MOUs) and electric cooperatives (co-ops) that implement retail competition.

In January 2001, the Commission adopted new P.U.C. SUBST. R. 25.214, *Terms and Conditions of Retail Distribution Service Provided by Investor Owned Transmission and Distribution Utilities*, to standardize requirements related to the interaction between REPs and TDUs.[8] As part of this rule, the Commission approved a standard pro-forma tariff that governs liability, service requests, switching, billing, metering, data exchange, dispute resolution, and outage and service request reporting. This rule and the pro-forma tariff apply to all investor-owned TDUs in Texas. However, the terms and conditions do not apply to the provision of transmission service by non-ERCOT utilities to retail customers, which is under the jurisdiction of FERC.

The Commission also adopted new P.U.C. SUBST. R. 25.215, *Terms and Conditions of Access by a Competitive Retailer to the Delivery System of a Municipally Owned Utility or Electric Cooperative that has Implemented Customer Choice*.[9] This rule incorporates a pro-forma tariff that is similar to the one for REPs operating in service areas of investor-owned TDUs, but also recognizes the different provisions that apply to MOUs and co-ops adopting customer choice as outlined in Chapters 40 and 41 of PURA.

The governing bodies of MOUs and co-ops have discretion as to when or if they will offer customer choice in their service areas. As of December 2002, Nueces Electric Cooperative and San Patricio Electric Cooperative have announced that they will open their systems to customer choice.

Texas is the only state with retail competition that has created pro-forma tariffs for utility distribution service, and this standardization appears to have facilitated the ability of REPs to conduct business in multiple areas of the state.

e. Pulse Metering

Electric pulse metering allows customers to receive a data from their electric meter that provides real-time or near real-time consumption information. Having access to the pulse information allows customers to control consumption, plan for electric payments, and detect problems with equipment that may result in abnormal consumption. Access to real-time

---

[8] *PUC Rulemaking Proceeding to Establish Terms and Conditions of Transmission and Distribution Utilities' Retail Distribution Service*, Project No. 22187, Order Adopting New § 25.214 and the Pro-Forma Tariff, Tariff for Retail Delivery Service (Jan. 23, 2001).

[9] *Id.*, Order Adopting New § 25.215 (Sept. 20, 2001).

consumption information can also facilitate the efficient operation of both wholesale and retail markets as it may encourage customers to change their usage patterns so that less of their consumption occurs during peak hours, when prices are the highest.

Automated Energy Inc. (AEI), a multi-state competitive energy services provider, representatives of customers, and several state agencies expressed difficulties in obtaining pulse-metering services from utilities. The underlying problems stemmed from Commission rules and orders that unintentionally precluded the TDUs from providing pulse service, because it was considered a competitive energy service.

In response to these concerns, the Commission adopted new P.U.C. SUBST. R. 25.129, *Pulse Metering,* and a pro-forma agreement titled *Agreement and Terms and Conditions for Pulse Metering Equipment Installation (PMEI agreement),*[10] which sets forth standard terms and conditions for the provision of this service. The rule clarifies that providing equipment to send and define pulses is not a competitive energy service, but is, instead, a utility service that must be offered under the standard tariff. Sending and defining pulses is integral to metering, which remains a utility service until 2004 for industrial and commercial customers. The processing of such pulse information remains a competitive service.

Under the rule, a utility must provide pulse-metering equipment on request (requestor pays for the equipment) under rates and procedures approved by the Commission. This rule provides better access to real-time consumption information and thereby enables customers to better manage their consumption in periods of high demand, when wholesale market prices are often at their highest.

f. Distributed Generation

Distributed generation refers to on-site generating units serving relatively small power loads such as small businesses, office buildings, hospitals, and even individual homes. The units can be connected to the utility for the purpose of selling electricity, can be interconnected without exporting power, or can be used without an interconnection. Distributed generation can reduce electricity costs and increase system reliability, especially during high-cost, peak-use periods.

To further facilitate the installation of distributed generation, the Commission approved pre-certification standards for distributed generation, allowing Commission-approved, nationally-recognized testing laboratories to designate specific models as safe to interconnect to the Texas power distribution grid.[11] Pre-certification of units eliminates the need for distribution utilities to undergo and require lengthy testing and evaluation of the effects of distributed generation on the local distribution grid, thereby lowering the cost and amount of time expended for customers to install such generation.

[10] *Rulemaking Concerning Pulse Metering,* Project No. 23952, Order Adopting § 25.129 and Amendments to § 25.341 and § 25.346 (Oct. 2, 2001).

[11] *Pre-Certification of Distributed Generation Units Pursuant to P.U.C. Subst. R. § 25.211(c)(12)(k),* Project No. 22318, Pre-Certification Document (Jan. 18, 2001).

g. Qualifying Facilities (QFs)

The Commission adopted amendments to P.U.C. SUBST. R. 25.242, *Arrangements between Qualifying Facilities and Electric Utilities*, to address the sale and purchase of electricity between qualifying facilities (QFs) and certain REPs in the restructured electric market.[12]

The Public Utility Regulatory Policies Act of 1978 (PURPA)[13] gives QFs the right to sell (put) electricity to electric utilities at "avoided costs." A state agency is expected to implement this requirement for "each electric utility, for which it has rate making authority."[14] PURPA defines "electric utility" broadly as: "any person, State agency, or Federal agency, which sells electric energy."[15] In the restructured Texas market, both REPs and power generation companies (PGCs) are electric utilities for purposes of PURPA.[16] However, the only entities that sell electricity in the restructured market over which the Commission has ratemaking authority are affiliated REPs providing price-to-beat service (PTB REPs) and providers of last resort (POLRs).

The Commission sought a waiver from the FERC from implementing PURPA upon the belief that an open, competitive market beginning on January 1, 2002 would render the PURPA power-purchase obligations unnecessary in Texas. The FERC ruled that the Commission must maintain its obligation to implement PURPA after unbundling and the commencement of competition and invited the Commission to develop a market-oriented method of determining avoided costs consistent with PURPA and retail competition in Texas.

The rule requires PTB REPs and POLRs to use the market clearing price of balancing energy as avoided costs for power put to a PTB REP or POLR for non-firm sales (as-available sales), but permits other arrangements to be made by the PTB REPs and QFs. The Commission indicated that, if a day-ahead and/or a real-time energy market develops in ERCOT, it will consider further amending the rule to base the pricing for QF energy on the prices in those markets.

h. Transmission Line Siting

A utility must obtain a certificate of convenience and necessity (CCN) from the Commission before constructing transmission facilities in Texas. The Commission is required to grant a CCN on a nondiscriminatory basis after considering the adequacy of existing service, the need for additional service, the effect of granting the certificate on the local utility and any utility serving the area, and other factors such as community values, recreational and park areas,

---

[12] *Rulemaking Concerning Arrangements Between Qualifying Facilities and Electric Utilities*, Project No. 24365, Order Adopting Amendments to § 25.242 (Jun. 24, 2002).

[13] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95.617,92 Stat.3117 (codified as amended in scattered sections of 15, 16, 42, and 43 U.S.C.) (PURPA)

[14] 16 U.S.C. § 824a-3(f)(1)(2000).

[15] 16 U.S.C. § 2602(4)(2000).

[16] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 31.002(10) and (17) (Vernon 1998 & Supp. 2003) (PURA).

historical and aesthetic values, environmental integrity, and the probable improvement of service or lowering of cost to consumers in the area.

During the 77th Legislative Session, several bills were introduced relating to transmission line siting issues and landowner concerns regarding the Commission's process of reviewing the need and siting of transmission lines. In response to the concerns highlighted in the proposed legislation, the Commission reviewed its rules relating to transmission siting to ensure that the process is fair to landowners and the surrounding community while still facilitating the construction of facilities in a timely and efficient manner.

The review resulted in rule amendments that require the Commission to consider the following factors in assessing the impacts of a new transmission line on directly affected landowners: [17]

- Whether the proposed routes utilize existing rights-of-way;
- Whether the proposed routes parallel existing rights-of-way; and
- Whether the proposed routes parallel property lines.

The Commission also revised its rules regarding the transmission siting process to facilitate landowner participation in the agency's transmission line proceedings, and to reflect changes in the restructured electric industry.[18]

A utility is now required to send direct mail notice to landowners having a habitable structure within 300 feet of the centerline of any of the potential routes for a proposed transmission line, or within 500 feet if the proposed transmission line is 230 kilovolts (kV) or higher. The required notice must include detailed information for landowners explaining the CCN process for the routing of transmission lines, including forms that may be used by the landowners to intervene in the proceeding or to provide comments concerning the case. The utility must also include a standard brochure entitled, "Landowners and Transmission Line Cases at the PUC," with the notice. This brochure is included in Appendix 3.

In addition, several types of transmission projects were exempted from the need to obtain a CCN, including upgrades or expansion of existing lines. The Commission believes that the amendments to the rules will facilitate landowner participation in CCN proceedings, while providing for the timely expansion of the transmission grid when needed.

i. Code of Conduct for Municipally Owned Utilities and Co-ops

The Commission adopted code-of-conduct rules for MOUs and co-ops that will apply once they have implemented customer choice and begin providing service outside their certificated areas.[19] The rule establishes broad safeguards to govern the interaction between the

---

[17] *Rulemaking Concerning Transmission Line Routing*, Project No. 24101, Order Adopting an Amendment to § 25.101 (Sept. 26, 2001).

[18] *Electric Utility CCN Rulemaking and Forms Changes*, Project No. 25515, Order Adopting Amendments to §§ 25.83 and 25.102, Repeal of § 25.101 and New § 25.101 (Oct. 8, 2002).

[19] *Code of Conduct for Municipally Owned Electric Utilities and Electric Cooperatives Pursuant to PURA § 39.157(e)*, Project No. 22361, Order Adopting New §25.275 (Mar. 8, 2001).

transmission and distribution business unit of an MOU or a co-op and its affiliates to avoid potential anticompetitive practices, such as cross-subsidization between regulated and competitive activities.

2. Completed Revisions of Rules Previously Adopted

In addition to adopting new rules to implement SB 7, the Commission has also found it necessary to revise certain rules after reviewing their operation in practice.

a. Provider of Last Resort (POLR)

POLR Service under the Original Rule. PURA § 39.106 requires that the Commission designate REPs in areas of the state in which customer choice is in effect to serve as POLRs. Each POLR is required to offer a standard retail service package for each class of customers designated by the Commission at a fixed, non-discountable rate approved by the Commission. In the event that a REP fails to serve its customers, the POLR must offer the standard service package to those customers with no interruption of service. The standard service package must also be available to any requesting customer.

In October 2000, the Commission adopted new P.U.C. SUBST. R. 25.43, *Provider of Last Resort*.[20] This rule required the POLR to charge a fixed rate that could not be changed over the term of the POLR contract. In addition, under the original POLR rule and customer protection rules, only the POLR had the authority to disconnect customers for nonpayment of electric services. Other REPs could only cancel a nonpaying customer's contract and transfer that customer to the POLR.

The Commission used a competitive bidding process to select the POLR for each customer class in each designated service area. Requests for proposals (RFPs) for POLR service were issued, but only one REP submitted a bid. The Commission designated non-bidding REPs to serve as POLRs in the areas where no bid was received and initiated negotiations to determine the rates for such service. Negotiations were successful for several of the areas, but the POLR rates and designation could not be agreed upon for other areas. PUC staff then initiated contested proceedings to designate REPs to serve as POLRs and to set the rates for such service in the remaining areas. These proceedings were highly contentious.

The initial rates for POLR service, whether approved by bid, negotiation, or contested-case proceeding, were substantially above the price to beat in all areas. This was due in part to the definition of POLR service at that time. POLRs generally were to serve two types of customers: (1) customers of a REP that chose to exit the market without making arrangements to transfer those customers to another REP, and (2) non-paying customers of a REP.

For the first set of customers, POLRs faced a tremendous risk in potentially being required to serve a large number of customers from an exiting REP with little notice at a fixed rate that was set far in advance of the event. POLRs desired a rate that would be compensatory in the event that wholesale market prices were high at the time of the transfer of customers.

[20] *Provider of Last Resort Rulemaking,* Project No. 21408, Order Adopting New § 25.43 (Oct. 20, 2000).

For the second set of customers, POLRs faced the risk of serving customers that had already demonstrated an inability or unwillingness to pay their provider for energy consumed. Because REPs did not have the ability to disconnect non-paying customers, as bundled utilities did under regulation, the only recourse was to transfer these customers to the POLR.

The combination of these risks led to the high rates initially set for the POLRs for 2002. Subsequent to Commission approval of the POLR rates, several parties appealed the orders and contracts with the POLRs to Travis County District Court, alleging that the rates were not just and reasonable, and that the Commission erred in the process it used to select POLRs and set the rates for POLR service.[21]

POLR Service under the Revised POLR Rules. Because of dissatisfaction with the results of the original POLR rule, the Commission initiated a rulemaking proceeding to alter the requirements for POLR service.[22] The rulemaking proceeding resulted in a new P.U.C. SUBST. R. 25.43, *Provider of Last Resort (POLR)*, and amendments to P.U.C. SUBST. R. 25.478, *Credit Requirements and Deposits*; P.U.C. SUBST. R. 25.480, *Bill Payment and Adjustments*, P.U.C. SUBST. R. 25.482, *Termination of Contract*, and P.U.C. SUBST. R. 25.483, *Disconnection of Service*.

The new rules reflect a fundamental change in POLR service by removing non-paying customers from the class of customers served by the POLR. The new rules allow non-affiliated REPs to transfer non-paying residential and small commercial customers to the affiliated REP for service at the price to beat. Also, the affiliated REP now has the authority to disconnect any of its customers for non-payment, and all REPs have authority to disconnect large commercial and industrial customers for non-payment, unless an existing contract provides for different treatment. This structure is much more analogous to the treatment of non-paying customers under regulation, and will remain in place until October 1, 2004. At that time, all REPs will have the authority to disconnect non-paying customers if the Commission finds that the adequate protections are in place for retail customers. As a result of these changes, the purpose of POLR service is now primarily to serve customers of a REP that chose to exit the market without making arrangements to transfer those customers to another REP.

The new POLR rule also reflects a significant shift in the POLR rate-setting process and rate structure. The new rule requires the Commission to compare bids for POLR service on price alone. In order to encourage REPs to bid to be POLR, winning bid rates can be adjusted on a monthly basis to reflect changes in wholesale market prices, thereby reducing the risk of providing POLR service. If no bids are submitted or all bids are rejected, the new rule requires

---

[21] *Office of Public Utility Counsel v. Public Utility Commission of Texas, et.al,* No. GN200633 (250th Dist. Ct., Travis County, Tex., Feb. 25, 2002); *Texas Legal Services Center v. Public Utility Commission of Texas, et.al.*, No. GN200751 (345th Dist. Ct., Travis County, Tex., Mar. 6, 2002). *Office of Public Utility Counsel v. Public Utility Commission of Texas and Staren Power, LLC, d/b/a Texas Star Energy Company*, No. GN200267 (126th Dist. Ct., Travis County, Tex., Jan. 25, 2002).

[22] *Rulemaking Proceeding to Amend Requirements for Provider of Last Resort Service,* Project No. 25360, Order Adopting New § 25.43, Repeal of Existing § 25.43, and Amendments to §§ 25.478, 25.480, 25.482, and 25.483 (Aug. 23, 2002).

the Commission to select POLRs by a lottery. Selected POLRs will provide service at specific rate levels required by the rule, in lieu of the negotiation and/or contested case process prescribed by the original POLR rule.

While the new POLR rule solved many of the problems encountered in the original POLR rule, the competitive process envisioned by the Commission has yet to perform adequately. For service beginning in 2003, only affiliated REPs were eligible to bid and/or be selected by lottery. Only Reliant submitted a POLR bid under the new process and was selected as POLR for several market areas. Neither TXU Energy Services, First Choice Power, nor AEP submitted bids under the revised rule. The Commission held a lottery for the areas where Reliant did not bid. The next time POLR service is bid out, however, a broader range of REPs will be eligible, which may lead to more bidders.

At the end of 2002, there were still a number of customers served by the initial (2002) POLRs because they were transferred prior to September 2002, when the new rules took effect. Rather than mandating the transfer of these customers to the affiliated REP (with whom these customers likely have a substantial outstanding bill), these customers received notice of the options available to them. The notice informed the customers that, by November 1, they could affirmatively choose to initiate service with the affiliated REP or another competitive REP, or they could initiate service with the new (2003) POLR at the Commission-approved rate. The remaining POLR customers who did not make an affirmative choice will be transferred in January 2003 to a competitive affiliate of the 2002 POLR that will continue to serve those customers at a rate specified by the competitive affiliate. This transition mechanism is also intended to encourage REPs to bid for POLR service because it could result in retention of customers by the POLR's competitive affiliate after the end of the POLR term.

b. Capacity Auction

The Commission's rule on capacity auctions is intended to promote competition in the wholesale market through increased availability of generation and increased liquidity by requiring affiliated PGCs to sell entitlements to at least 15% of their Texas generation capacity.

The Commission revised its capacity auction rule in 2002[23] to incorporate certain exceptions to the rule that were found to be necessary in practice. A major change to the rule was the inclusion of "switching procedures," which change the nature of the auctions by allowing a bidder to move its bid among different PGC auctions. Bidders can even change the type of product it is bidding on if the bidder feels there is more value in another auction. The expected result of the switching procedures is more efficient prices. The first auction under the revised rule occurred on October 8, 2002.

[23] *Rulemaking Proceeding to Revise Substantive Rule 25.381, Capacity Auctions,* Project No. 24492, Order Adopting Amendments to § 25.381 (June 19, 2002).

3. Pending Rulemakings

a. Load Profiling

The Commission has proposed a new rule relating to load profiling and load research.[24] Customers that do not have meters that record each 15-minute period of energy usage have their usage settled on an assumed usage pattern (known as a "load profile"). ERCOT currently has nine profile types, which are each applied to as many as eight weather zones to generate 65 unique load profiles for each day. The current profiles were built based on utility load research data, which is also important in maintaining, evaluating and improving the profiles. However, several customers have argued that the existing profiles do not adequately reflect their usage patterns.

The proposed rule would provide a means for ERCOT to obtain the actual interval meter data it needs to update and maintain existing profiles and create new ones. It also would allow REPs access to the data used to generate the profiles and would require that a process be developed so that a requester of a new profile may collect a fee from others who subsequently use the profile, eliminating current "free-rider" disincentives to initiate profiling research.

The proposed rule was published in the *Texas Register* on October 25, 2002 and the Commission anticipates adopting a final rule in the first quarter 2003.

b. Oversight of Independent Organizations in a Competitive Market

PURA § 39.151 establishes guidelines for independent organizations, such as the ERCOT ISO, that are responsible for electric system reliability, transmission access, wholesale settlements, and customer registration. The Commission's rules currently do not clearly define the responsibilities of independent organizations, and market participants have raised concerns regarding the operation and oversight of these organizations.

The Commission has proposed amendments to P.U.C. SUBST. R. 25.361, *Electric Reliability Council of Texas (ERCOT)*, and a new P.U.C. SUBST. R. 25.362, *Electric Reliability Council of Texas (ERCOT) Governance*.[25] The proposed new rule and amendments are intended to provide clear standards, guidelines, and expectations related to the operation and management of ERCOT, while allowing ERCOT the latitude to develop and implement its own specific policies and procedures.

The Commission has also proposed a clear requirement that ERCOT provide requested information to the Commission, even if the information is designated as confidential under the ERCOT Protocols. The Commission believes this requirement is needed to ensure that the

[24] *Load Profiling and Load Research Rulemaking,* Project No. 25516, Proposal for Publication of New § 25.131 (Oct. 11, 2002).

[25] *PUC Rulemaking on Oversight of Independent Organizations in the Competitive Electric Market,* Project No. 25959, Proposal for Publication of an Amendment to § 25.361 and New § 22.362 (Sept. 27, 2002).

Commission and its staff can continue to effectively monitor the operation of the competitive market without lengthy delays in acquiring needed information.

In addition to these rules, the Commission has also proposed a new procedural rule, P.U.C. PROC. R. 22.251, *Review of Electric Reliability Council of Texas (ERCOT) Action.*[26] The proposed rule is necessary to establish clear procedures for market participants to make formal complaints regarding decisions or acts made (or not made) by ERCOT. The scope of permitted complaints includes ERCOT's performance as an independent organization under PURA and ERCOT's promulgation and enforcement of rules relating to reliability, transmission access, customer registration, and settlement.

The Commission anticipates adopting a final rule in the first quarter of 2003.

c. Performance Measures

As discussed in further detail in Section IV.C of this report, the Commission has been collecting certain information relating to the operation of the competitive retail market, including switch transactions, move-in/move-out transactions, and billing transactions.

The Commission has published a proposed rule and filing package codifying these data requests and other requests for data on the development of the competitive retail market.[27] The Commission anticipates adopting a final rule in the first quarter of 2003.

d. Price to Beat

After processing of the first set of requests for adjustments to the price-to-beat fuel factors (see Section III.B.3), the Commission initiated a review of P.U.C. SUBST. R. 25.41, *Price to Beat* to ensure that the rule provided for appropriate adjustment mechanisms.[28]

The Commission has published proposed amendments to the price-to-beat rule. The amendments do not change the fundamental approach to adjusting the price-to-beat fuel factors, but are intended to ensure that adjustments to the fuel factors reflect true and significant changes in market prices, not temporary spikes. The proposed amendments also provide the Commission more flexibility in processing requests.

The most significant provision in the amendments is further clarification regarding the Commission's ability to make adjustments to the price to beat following the stranded cost true-up proceedings that will be conducted in 2004. The proposed rule would require affiliated REPs to adjust the fuel factor downward if natural gas prices have fallen below the level used to set the fuel factors in effect at that time. The original rule did not require the affiliated REPs to reduce the price to beat if gas prices fell. The proposed rule would require a price adjustment in 2004

---

[26] *Id.*, Proposal for Publication of New § 22.251 (Sept. 27, 2002).

[27] *PUC Proceeding to Establish Performance Measures Relating to the Competitive Retail Electric Market*, Project No. 24462, Proposal for Publication of New § 25.88, (Sept. 27, 2002).

[28] *Revisions to the Provisions of P.U.C. Subst. R. 25.41 Relating to the Price to Beat Fuel Factors,* Project No. 26556, Proposal for Publication of Amendments to § 25.41 (Nov. 8, 2002).

under those circumstances. The proposed amendments also include an adjustment to the base-rate portion of the price to beat to reflect changes in non-bypassable charges, including additional stranded cost charges resulting from the true-up proceedings. This provision is intended to ensure that increases in non-bypassable charges do not significantly reduce or eliminate headroom under the price to beat for non-affiliated REPs to compete.

The Commission anticipates adopting final amendments to the rule in the first quarter of 2003.

e. Competitive Metering

PURA § 39.107(a) prescribes that metering services for commercial and industrial customers are to become competitive on January 1, 2004. Many other states that have opened their markets to retail competition have also required metering to be competitive. However, competition has been very slow to develop in this segment of the industry, in part because of the economies of scale that may be related to performing these tasks in a specific geographic region.

The Commission has initiated a rulemaking to prescribe the terms and conditions for competitive metering, and anticipates a proposed rule to be published in the first quarter of 2003.[29]

f. Competitive Energy Services

TDUs are prohibited from performing competitive energy services by PURA § 39.051(a) and Commission rules. The Commission adopted P.U.C. SUBST. R. 25.343 in 1999 to delineate those services considered to be competitive energy services and to establish a process for the Commission to determine whether specific services are competitive.

The Commission granted petitions to permit utilities to continue providing non-roadway, outdoor-security lighting services and maintenance and ownership of certain facilities on retail customers' premises (*e.g.*, transformers leased to a customer by the utility) because a competitive market did not yet exist for these services. The Commission has initiated a rulemaking to determine, among other things, whether these services are appropriately considered competitive services, or if they should continue to be provided by TDUs.[30]

The Commission anticipates publishing a proposed rule in the first quarter of 2003.

g. Customer Protection Rules

The Commission has also begun a review of its customer protection rules to ensure that the rules provide adequate and appropriate protections for retail customers, while at the same time, not requiring REPs to incur unnecessary compliance costs. The Commission anticipates considering the following amendments to the rules:

---

[29] *Rulemaking to Address Competitive Metering,* Project No. 26359 (pending).

[30] *PUC Rulemaking to Address Competitive Energy Services,* Project No. 26418 (pending).

- Clarify requirements relating to the issuance of bills by REPs to retail customers in a timely manner;
- Clarify requirements related to terms of service documents, Electricity Facts Labels, and Your Rights as a Customer documents (including the development of a Commission-approved, pro-forma terms of service documents);
- Clarify procedures to be followed by builders and developers, TDUs, and REPs regarding new construction and establishment of service;
- The establishment of more detailed procedures to be followed by REPs to return customers to their chosen provider in the event the customer is "slammed" by the REP (intentionally or unintentionally);
- The establishment of more detailed procedures for REPs establishing service for new customers or customers who have been disconnected for non-payment;
- An evaluation of the reasonableness of current disclosure requirements relating to advertising;
- An examination of current requirements related to door-to-door marketing by REPs to determine if additional verification standards are needed to protect customers from deceptive marketing practices.

The Commission expects that rule amendments will be proposed near the end of the first quarter of 2003.

h. Wholesale Market Code of Conduct

Over the course of the past year, numerous generation companies and power marketers have been accused of, or have admitted to, engaging in activity that may be detrimental to the development of a robust competitive market. Those practices include submitting false schedules in order to receive payments to relieve congestion, violating market rules in other parts of the country, withholding generation from the wholesale market in attempts to raise prices, and "wash trading" (conducting simultaneous purchases and sales with the same party at equal prices in order to inflate trading volumes, reported revenue, or prices).

The Commission has initiated a project to determine whether it is appropriate to require wholesale market participants to abide by a code of conduct as a condition of operating in the ERCOT market.[31]

The Commission expects that rule amendments will be proposed near the end of the first quarter of 2003.

i. Wholesale Market Design Issues

The Commission has opened a project to evaluate the operation of the wholesale market during the first year of competition to determine if adjustments are needed to the wholesale

[31] *PUC Rulemaking Proceeding on Code of Conduct for Wholesale Market Participants*, Project No. 26201 (pending).

market design, or if a different structure should be explored.[32] The issues being addressed include the proper system to manage transmission congestion (*i.e.*, the current "zonal" model being used in ERCOT versus a location marginal pricing or "nodal" model), whether ERCOT should operate day-ahead and real-time energy markets, and requirements related to the submission of balanced versus unbalanced schedules. The associated costs of modifying the ERCOT market structure are also being considered.

The Commission expects that rule amendments will be proposed near the end of the first quarter of 2003.

j. Wholesale Market Price Transparency

The Commission has opened a rulemaking to explore requiring all market participants to report their bilateral trades to the Commission as a means of providing added transparency to the marketplace, as well as to aid the Commission in monitoring prices in the wholesale market and the potential exercise of market power and other anti-competitive behavior.[33]

The Commission expects that rule amendments will be proposed near the end of the first quarter of 2003.

k. Generation Adequacy

As discussed further in Section V, Emerging Issues, the Commission is considering the appropriate mechanisms for ensuring the adequacy of generation capacity in the ERCOT market.[34]

[32] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376 (pending).

[33] *Disclosure of Information Related to Electricity Transactions Originating or Terminating in Texas*, Project No. 26188 (pending).

[34] *Rulemaking Concerning Planning Reserve Margin Requirements*, Project No. 24255 (pending).

B. ADOPTION OF DELIVERY RATES, PRICE-TO-BEAT RATES, AND PROVIDER OF LAST RESORT RATES

During 2001, the Commission completed various proceedings to set non-bypassable charges and to approve price-to-beat and POLR rates to be effective January 1, 2002.

1. Updates of Non-Bypassable Charges

All REPs must pay PUC-approved "wires" fees to the TDU for delivering electricity to the REP's customers who live in that TDU's service area. These charges are also called "non-bypassable fees" because every customer pays these charges, regardless of which REP the customer chooses. Non-bypassable fees include the following:

- **Transmission and Distribution rates—**charges for delivering electricity over TDU wires to REP's customer each month.
- **System Benefit Fund fee—**pays for a statewide low income discount program and energy efficiency programs, the PUC customer education program, and reimbursement to school districts due to losses in property taxes related to restructuring.
- **Competition Transition Charge—**pays for stranded costs. Stranded costs are the difference between book value and market value of utility assets. The PUC has determined that no utility is estimated to have stranded costs, so no CTCs were set. This may change after the final market evaluation of stranded costs in 2004.
- **Excess Mitigation Credit—**a credit on non-bypassable charges designed to return the excess recovery of stranded costs.
- **Transition Charge** (if any)—pays for securitized regulatory assets. Utilities were allowed to refinance debt on assets in order to reduce the overall payments and reduce costs for ratepayers;
- **Nuclear Decommissioning fee** (if any)—Owners of nuclear power plants are required by the National Regulatory Commission (NRC) to decommission their nuclear power plants once they reach the end of their useful life. Utilities are required to certify that funds for decommissioning will be provided when needed.

a. Stranded Cost Recovery

Stranded costs are expenditures related to utility generation facilities incurred under the previous system of regulation that are not recoverable in a competitive market. PURA specifically defines these costs as the difference between the book value and market value of those investments.[35] Generally, the generation investments that may be "stranded" are costs related to the construction of nuclear generation plants and one lignite plant in the state. While these plants have very low operating costs, the capital costs may not be fully recovered in a competitive market if the market price of electricity is not sufficiently high. The lower the market price of electricity, the higher stranded costs are likely to be.

[35] PURA § 39.251(7).

The first estimates of stranded costs were sufficiently high that paying them would have been a significant burden to ratepayers.[36] As a result, the Legislature authorized utilities to use a portion of their revenues from 1998 through 2001 to mitigate potential stranded costs. In 2001, three utilities, Reliant Energy HL&P (Reliant), TXU Electric Company (TXU), and Central Power and Light Company (CPL), had significant balances of $2.097 billion, $1.865 billion, and $55 million, respectively, in their mitigation accounts.

Securitization is a transaction in which a utility receives a lump-sum payment of stranded costs in lieu of collecting the costs through its regulated rates over many years. The lump-sum payment is financed through the issuance of low-risk debt securities to third-party investors. SB 7 and Commission rules allowed utilities to securitize a portion of their stranded costs related to "regulatory assets" prior to updating the estimates of the utilities' stranded costs.[37]

At the same time as these utilities were mitigating stranded costs and securitizing regulatory assets, the stranded-cost estimates changed dramatically. Natural gas prices increased sharply, and the estimated market price of electric power had risen enough that the 2001 updates indicated that stranded costs had disappeared. The mitigation accounts consequently appeared to have been unnecessary.[38] In November 2001, the Commission ordered that the accrual of mitigation be reversed and that these funds be returned to ratepayers. Summaries of the current status of stranded costs for the major utilities are below:

Central Power and Light (CPL). The Commission approved a request by CPL to securitize $764 million of regulatory assets plus transactions costs. Several parties filed requests for judicial review of the Commission's financing order. The Travis County District Court and Texas Supreme Court upheld the financing order, and CPL subsequently issued bonds. Securitization is expected to save CPL's electric customers at least $90 million over the next 12 years.

Later, in CPL's UCOS proceeding, the Commission ordered that $55 million in excess earnings collected by CPL from 1999 through 2001 be returned to ratepayers through an "excess mitigation credit (EMC)" over a period of five years. The EMC is a credit to other non-bypassable charges set by the Commission.

Reliant Energy, HL&P. The Commission approved a request by Reliant Energy HL&P to securitize $740 million of regulatory assets plus transactions costs. Securitization is expected to save Reliant's electric customers at least $350 million over the next 12 years.

---

[36] *Report to the 75th Legislature, Volume III, Public Utility Commission of Texas (1997 ECOM Report)* (January 1997); *Report to the Texas Senate Interim Committee on Electric Utility Restructuring, Potentially Strandable Investment (ECOM) Report, 1998 Update* (April 1998).

[37] Regulatory assets are the generation-related portion of the Texas jurisdictional portion of the amount reported by the electric utility in its 1998 annual report on Securities and Exchange Commission Form 10-K as regulatory assets and liabilities, offset by the applicable portion of generation-related investment tax credits permitted under the Internal Revenue Code of 1986.

[38] A major determinant of stranded costs is the price of electricity that is available on the open market. This price is strongly affected by the cost of natural gas. As the market price rises, the difference between it and the utility's cost of producing power decreases. This in turn reduces stranded cost.

In Reliant's UCOS proceeding, the Commission ordered Reliant to reverse approximately $863 million in redirected depreciation from transmission and distribution assets to generation assets and to return $1.242 billion in excess earnings over seven years through an EMC. The effect of both decisions was to reduce non-bypassable charges to ratepayers.

Texas-New Mexico Power Co. (TNMP). At the time of TNMP's UCOS proceeding, TNMP's updated estimate of stranded costs was approximately $0.00. No securitization was authorized, and the Commission decided not to require the return of mitigation.

TXU Electric Company. TXU originally requested securitization of $1.65 billion. The Commission in the original proceeding authorized securitization of only $363 million, and TXU and other parties filed requests for judicial review of the Commission's financing order. The District Court and Texas Supreme Court ruled that the Commission erred in several aspects of processing the case, and remanded the case to the Commission for further consideration.

In TXU's UCOS proceeding, the Commission ordered TXU to reverse $798 million in redirected depreciation and to return $888 million in excess earnings through an EMC over seven years.

Subsequent to these orders, the Commission authorized TXU to securitize a total of $1.3 billion as part of a broader settlement under which TXU agreed to forego any further stranded cost recovery and appeals of Commission decisions in TXU's UCOS case. The Commission found that the settlement provided tangible and quantifiable benefits to ratepayers, eliminated the risk of large remaining stranded costs in 2004, and provided certainty to both customers and market participants as to the level of rates.

Key elements of the settlement included:

- TXU was permitted securitization of $1.3 billion of regulatory assets;
- TXU agreed not to seek recovery of non-regulatory-asset stranded costs, conclusively determined to be $0.00;
- TXU agreed to return most prior stranded cost mitigation;
- TXU agreed not to seek environmental retrofit stranded cost recovery;
- TXU agreed not to seek recovery of costs related to the repurchase of minority owner interest in the Comanche Peak nuclear generating station;
- TXU agreed not to seek recovery of the December 31, 2001 unrecovered fuel expenses;
- TXU and the other parties agreed to set the "retail clawback" obligation of the affiliated REP at a specific level; and
- TXU and other parties agreed to seek dismissal of other pending administrative and judicial actions.

Some parties have requested judicial review of the Commission's orders approving the settlement. Those appeals are currently pending in Travis County District Court.[39]

[39] *Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities, et.al., vs. Public Utility Commission of Texas*, No. GN2-02825 (345th Dist. Ct., Travis County, Tex. August 16, 2002).

Entergy Gulf States, Inc. Although the Commission has not yet issued a final order in Entergy Gulf States Inc.'s (Entergy's) UCOS proceeding due to the delay in retail competition in Entergy's service area, the Commission has issued an interim order approving a non-unanimous settlement that also finally resolved Entergy's stranded costs at $0.0, without the need for a true-up in 2004. The settlement also ensured that Entergy's Texas customers would not face additional charges or increases in rates that may result from several pending appeals of Commission orders.

b. Transmission and Distribution Charges

In March 2000, nine investor-owned utilities filed applications for approval of UCOS rates to be charged by the successor transmission and distribution utilities after the introduction of competition. The applications were processed as contested cases. The Commission completed the UCOS proceedings for each of the six investor-owned utilities that opened to full retail competition in January 2002, and approved final orders for each of the unbundled TDUs, setting charges for transmission and distribution service, including metering services. Final rates were not approved for the other three areas because full retail competition was delayed in those areas.

Setting rates for independent TDUs presented several unique challenges as compared to traditional rate cases. First, the costs of the integrated utilities had to be separated into different functions (*i.e.*, generation, transmission and distribution, metering, customer service, and billing costs). Next, the Commission had to determine the proper rate of return and capital structure of a separate TDU, an entity that did not exist anywhere nationally until SB 7. Finally, the Commission had to determine the appropriate grouping of customers into customer classes and design rates for transmission and distribution service.

The Commission conducted a generic proceeding to resolve many of these issues in a standard fashion for all utilities. Decisions on the generic issues were then incorporated into decisions on utility-specific issues made in individually litigated proceedings at SOAH. Partial and/or complete settlements were reached in the CPL, West Texas Utilities (WTU), Southwestern Electric Power Co. (SWEPCO), Entergy, and TNMP proceedings and were subsequently approved by the Commission. In May 2001, the Commission ordered the implementation of interim rates to be in effect for the pilot project, and finalized the rates (except for SWEPCO and Entergy) in the fall of 2001 for service beginning on January 1, 2002.

The Commission delayed the issuance of final orders for SWEPCO and Entergy due to the delay of competition in those areas, finding that it would be inappropriate to permit the companies to unbundle in advance of full retail competition in those areas.

c. System Benefit Fund Fee

In order to ensure that the system benefit fund would be sufficient to meet all of the funding obligations outlined in the statute, the Commission set the system benefit fee at sixty-five cents per MWh, the maximum level authorized by statute.

2. Adoption of Price-to-Beat Rates

Customers who did not choose a new REP were transferred automatically to their utility's affiliated retail electric provider in January 2002. Residential and small non-residential electric customers (with a peak demand of 1 MW or less) who remain with the affiliated REP are charged a regulated rate, called the price to beat.

The Commission conducted various cases in the fall of 2001 to set the price-to-beat rates for the affiliated REPs. The most controversial set of proceedings involved the setting of the fuel factor portions of the price to beat. REPs generally argued that the Commission had set the fuel factors too low, making it difficult for them to compete against the price to beat. Consumer representatives generally argued that the Commission set the fuel factors too high, and inappropriately included certain costs. Several parties have requested judicial review of the Commission's orders in District Court.

The Commission did not issue orders for Entergy or SWEPCO due to the delay in full retail competition for those areas.

The total price-to-beat rates for residential customers for each affiliated REP are shown in the following table. In the case of TNMP (First Choice), CPL, and WTU, base rates changed a level other than 6% due to changes in rates between January 1, 1999 and December 31, 2001 resulting from merger proceedings.

Also, significant increases in the price of natural gas during the winter of 2000-2001 resulted in the fuel factor portions of the pre-2002 rates rising significantly and also required the imposition of fuel surcharges to recover past uncollected fuel expenses. Natural gas prices fell significantly at the end of 2001, resulting in significant reductions to the fuel factor portion of the price-to-beat rates. Also, fuel surcharges that were in place during 2001 terminated in December 2001. As a result, customers received in excess of a 6% reduction in their total rates as compared to rates in effect on December 31, 2001.

Table 3: Comparison of Price-to-beat Rates

Affiliated REP	December 31, 2001 (cents per kWh)				January 1, 2002 (cents per kWh)			% Reduction (Total)
	Base Rates	Fuel Factor	Fuel Surcharge	Total	Base Rates	Fuel Factor	Total	
TXU Energy	6.05	3.10	0.52	**9.67**	5.76	2.49	**8.25**	14.6%
Reliant Resources	6.47	3.21	0.72	**10.40**	6.08	2.53	**8.62**	17.2%
First Choice (TNMP)	6.39	3.80	0.38	**10.57**	6.48	2.18	**8.66**	18.1%
Mutual Energy CPL	5.89	3.68	-	**9.57**	5.61	3.19	**8.80**	8.1%
Mutual Energy WTU	5.43	4.24	0.31	**9.98**	5.09	3.79	**8.88**	11.0%
TXU SESCO	6.21	-	-	**6.21**	5.99	-	**5.99**	3.6%

*All prices in cents per kWh for a customer using an average of 1000 kWh per month
SOURCE: 2001 and 2002 Residential tariffs.

The changes in rates for small commercial customers are comparable to those experienced by residential customers. The savings that customers have received as a result of the imposition of these rates as compared to rates in effect in 2001 are discussed in the next section.

3. Price-to-Beat Fuel Factor Adjustments

In setting the initial price-to-beat fuel factors, the Commission utilized a natural gas price of $3.11 per million British thermal units (MMBtu) for all affiliated REPs. This estimated price was a ten-day average of forward prices for each month of 2002. The Commission’s rule permitted the affiliated REPs to request an adjustment to their fuel factors in the event that natural gas futures prices increased by more than 4% from the $3.11 per MMBtu price.

Although natural gas prices dropped in the early months of 2002, prices began to rise significantly in March and April of 2002. All of the affiliated REPs (except TXU-SESCO) subsequently requested adjustments to their price-to-beat fuel factors in order to reflect increases in the price of natural gas in the range of 16%-24%, and these cases were referred to SOAH for processing.

The Commission received proposed orders from SOAH, but determined that it would be appropriate to more explicitly test several of the assumptions embodied in the price-to-beat rule to determine if they were in fact valid, and remanded the cases to SOAH for that purpose. The affiliated REPs subsequently requested the District Court to enjoin the remand proceedings and sought a writ of mandamus from the court requiring the Commission to rule on the pending requests. The District Court agreed with the affiliated REPs, and issued temporary injunctions halting the remand proceedings.

The Commission, in response to the District Court's orders, approved the requests of the affiliated REPs, with slight downward adjustments recommended by the PUC staff in order to comply with the methodology outlined in the Commission's rule.

The resulting residential fuel factors and total price-to-beat rates, as compared to the original price-to-beat fuel factors and total price-to-beat rates, are listed below. Changes in small commercial rates are comparable to those shown here for residential customers:

Table 4: Revised Price-to-beat Rates, Effective September 2002

Affiliated REP	Initial Fuel Factor (cents per kWh)	Initial Total PTB (cents per kWh)	Revised Fuel Factor (cents per kWh)	Revised Total PTB (cents per kWh)	% change in fuel factor	% change in total PTB
TXU	2.49	8.25	2.89	8.66	16%	5%
Reliant	2.53	8.62	3.04	9.12	20%	6%
First Choice (TNMP)	2.18	8.66	2.67	9.15	22%	8%
Mutual Energy CPL	3.19	8.80	3.89	9.52	22%	8%
Mutual Energy WTU	3.79	8.90	4.64	9.73	22%	9%

*All prices in cents per kWh for a customer using an average of 1000 kWh per month.
SOURCE: Affiliated REPs Residential Tariffs, effective September 2002.

Subsequent to the Commission's approval of the revised fuel factors, natural gas prices continued to rise through the fall of 2002. Reliant Resources filed for a second adjustment in November 2002 to reflect a further 7% increase in natural gas prices. The Commission approved Reliant's application in December 2002.

As discussed in Section III.A.3 of this report, the Commission has proposed several amendments to the price-to-beat rule in order to ensure that it provides for appropriate adjustments to the price to beat.

4. Provider of Last Resort Rates

As discussed in Section III.A.2 of this report, the Commission has approved POLR rates under two different rules. The original POLR rules contemplated a sealed-bid competitive bidding process to set the POLR rates. The Commission conducted that process, and accepted the bids of TXU Energy Services to provide POLR service in the majority of the state. The Commission designated POLRs for the remaining areas of the state, and was able to negotiate POLR rates for several of the other areas. Ultimately, the Commission held contested case proceedings to set POLR rates for the remaining areas.

Under the revised POLR rules adopted by the Commission, the Commission again held a competitive bidding process to designate POLRs and establish rates for POLR service to be effective on January 1, 2003. Under the revised rules, however, bids were made public with the opportunity for interested parties to comment on the bids. Bids could also not exceed 125% of the price to beat for residential and small commercial customers. The bids of Reliant Resources complied with the rule limitations, and POLR service was awarded to Reliant in most areas of the state. The Commission then held a lottery to select POLRs for the remaining areas.

A summary of residential POLR rates under the original rule and the revised rule is included in the table below:

Table 5: Summary of POLR Rates for 2002 and 2003

TDU Service Area	2002 POLR Rates (cents per kWh)	2003 POLR Rates (cents per kWh)	% Reduction 2003 vs. 2002
CenterPoint	11.96	10.83	9.45%
Oncor	10.54-11.05	10.00	5.12%-9.50%
WTU	12.86	12.37	3.81%
CPL	12.22	11.08	9.33%
TNMP	12.13	10.99	9.40%

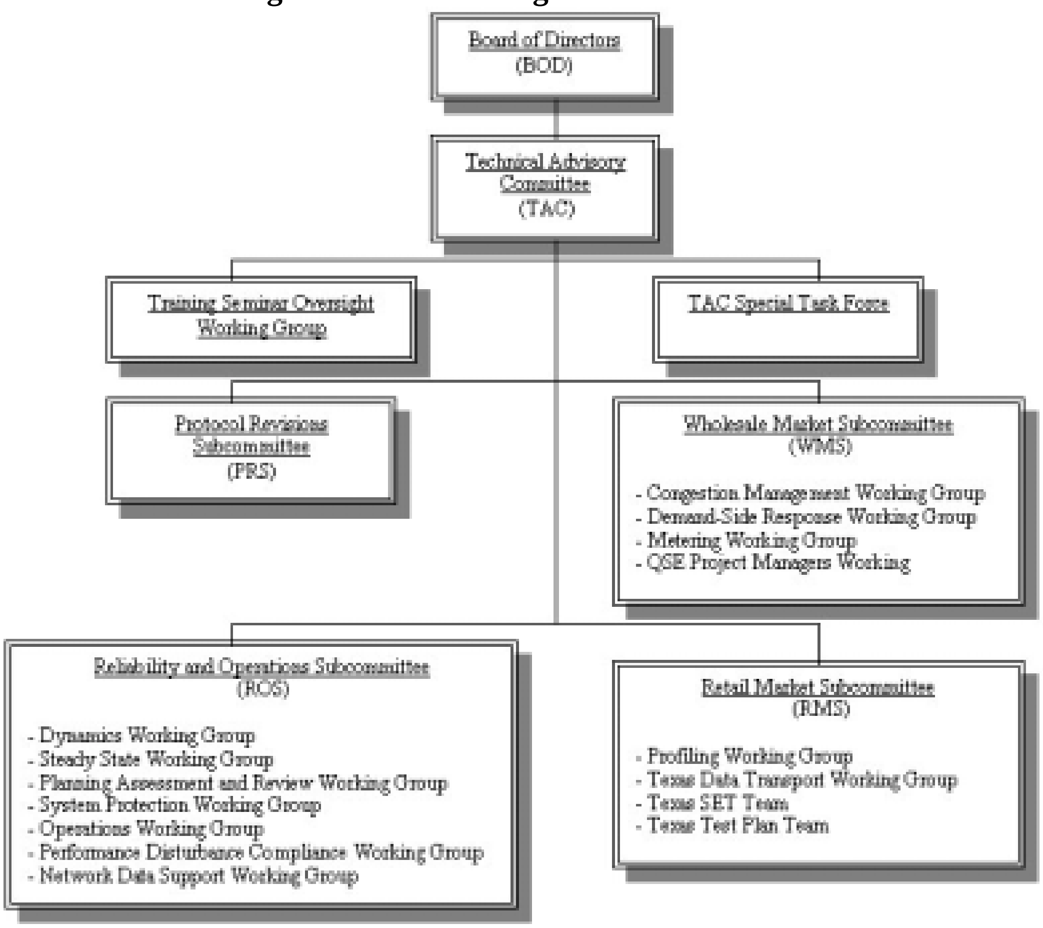
* All prices in cents per kWh for residential customer using an average of 1000 kWh per month.
SOURCE: POLR rates as approved in Docket Nos. 26559, 26560, 26561, 26562, and 26563.

C. APPROVAL OF ERCOT GOVERNANCE STRUCTURES AND ERCOT PROTOCOLS

1. ERCOT Governance

The Commission is the primary regulatory authority for ERCOT. ERCOT is governed by a Board of Directors, made up of members from each of four major stakeholder groups and consumer representatives. A Technical Advisory Committee (TAC) makes policy recommendations to the Board of Directors. The TAC is assisted by four standing subcommittees, as well as numerous workgroups and task forces. The four standing subcommittees are the Protocol Revisions Subcommittee (PRS), Wholesale Market Subcommittee (WMS), Reliability and Operations Subcommittee (ROS), and Retail Market Subcommittee (RMS).

Figure 6: ERCOT Organizational Chart



ERCOT's Board of Directors appoints ERCOT's Chief Executive Officer (CEO) and Chief Operations Officer (COO) to direct and manage ERCOT's day-to-day operations. They are accompanied by a team of executives, managers, and ERCOT staff, who are responsible for critical components within ERCOT's four operations areas. Additionally, ERCOT has recently appointed a Chief Information Officer (CIO) and Chief of Market Operations (CMO) to better manage the day-to-day operation of the retail and wholesale market.

The Board that was seated for 2002 included a total of 25 members (Directors) as follows:

1. **Generator Segment:** three Independent Generators, one Investor-Owned Utility (IOU), and one Municipally Owned Utility (MOU).
2. **Transmission and Distribution Segment:** one IOU, one MOU, two Cooperatives, and the Lower Colorado River Authority (LCRA).
3. **Retail Sales Segment:** one IOU, one Cooperative and three Independent REPs.
4. **Wholesale Sales Segment:** one MOU and three Independent Power Marketers.
5. **Consumer Segment:** the Public Counsel as an ex officio voting member, one representative of Residential Consumers, one representative of Commercial Consumers, and one representative of Industrial Consumers.
6. The CEO of ERCOT as an ex officio voting member.
7. The Chairman of the Public Utility Commission of Texas ("PUCT") as an ex officio non-voting member.

In response to concerns raised by the Electric Utility Restructuring Legislative Oversight Committee regarding the size and independence of the Board of Directors, the Board developed a restructuring plan that will result in a transition to a hybrid stakeholder/independent board by December 2003.

The first step in the transition was to reduce the number of members per segment to two for 2003. Additionally, three independent directors will be seated in June 2003. The 2003 Board(s) will be constituted as shown in the following chart:

Table 6: 2003 ERCOT Board Structure

Two MOU **Two Co-op** **Two IOU** **LCRA** **(**One designated alternate for each Segment)	**Three Independent Directors (July 2003)** (with backgrounds in banking, insurance and risk management, regulation, and/or IT)
Two Independent REP **Two Independent Generator** **Two Independent Power Marketer** (One designated alternate for each Segment)	**One Industrial Consumer** **One Commercial Consumer** **One Residential Consumer** **Office of Public Utility Counsel**
ERCOT CEO	
PUCT Chair (non-voting)	
TOTAL: January 2003 - May 2003 -- 19 members (18 votes) **June 2003 – December 2003 – 22 members (21 votes)**	

For the 2004 Board, the segment representatives would be reduced to one per segment, and the board would be constituted as follows:

Table 7: 2004 ERCOT Board Structure

One MOU **One Co-op** **One IOU** **(**One designated alternate for each Segment)	**Three Independent Directors** (with backgrounds in banking, insurance and risk management, regulation, and/or IT)
One Independent REP **One Independent Generator** **One Independent Power Marketer** (One designated alternate for each Segment)	**One Industrial Consumer** **One Commercial Consumer** **Office of Public Utility Counsel**
ERCOT CEO	
PUCT Chair (non-voting)	
TOTAL: 14 members (13 votes)	

For selection of independent directors, a nomination committee consisting of one representative from each segment would nominate candidates for membership, who would be required to meet certain criteria to qualify as independent. After the nominations are approved by the membership, they must then be approved by the Commission. Board members would serve staggered, two-year terms. No board member would serve more than four consecutive two-year terms.

The revised ERCOT governance structure and transition plan were approved by the Commission in December 2002.

2. Approval of ERCOT Protocols

The ERCOT Protocols were developed by the market participants. The Protocols provide detailed requirements and procedures governing wholesale and retail market operations, including transmission access, scheduling, dispatch, ancillary services, congestion management, settlement and billing, metering, customer registration, market information, testing, and dispute resolution. Among other things, the Protocols include timing specifications for market participants and ERCOT to send or process electronic transactions, such as switch requests and invoices. The computer and operating systems of ERCOT and market participants were designed to execute market functions as specified by the Protocols and Commission rules.

The Protocols reflect an effort by stakeholders to restructure the ERCOT market in order to allow greater access to the transmission grid by all market participants, to increase wholesale competition, and to implement retail competition. In approving the Protocols, the Commission ordered a number of revisions, and it established various deadlines and target dates for making those changes. The approved Protocols contained a number of important provisions that could not be implemented until the ERCOT computer systems could support them; however, the Commission ordered ERCOT to implement them as expeditiously as possible.

The changes to the Protocols required by the Commission include:

- A bid cap of $1,000 per MWh in the ERCOT-administered balancing energy ancillary service market as a “circuit breaker” against the possible exercise of market power by generation entities;
- Clear requirements to convert to the direct assignment of both interzonal and intrazonal transmission congestion costs after those costs reach $20 million for a rolling 12-month period, unless ERCOT finds it infeasible to implement direct assignment (in the case of intrazonal congestion);
- Changes in ERCOT’s procurement of ancillary services to minimize gaming opportunities in those markets;
- Requirements that at least three bids from unaffiliated generation resources be received in order for market prices to be used to relieve local congestion;
- Changes related to the provision of reliability must run contracts; and
- Directives for ERCOT to aggressively and thoroughly encourage load participation in ancillary services markets.

The ERCOT Protocols became effective June 1, 2001, but were not fully implemented until July 31, 2001, the date on which ERCOT assumed the role of control area operator for the entirety of the ERCOT grid. The control area operator is responsible for ensuring that the supply of and demand for electricity match in real time and that the frequency of the grid remains stable and reliable. Operation of the ERCOT market as a single control area managed by an independent system operator ensures that the procurement of ancillary services needed to maintain reliability is fair and non-discriminatory. Additionally, the financial settlement of wholesale transactions conducted through ERCOT is significantly simplified with a single control area.

a. Transmission Congestion

One of the fundamental market design elements in the Protocols is that ERCOT will use a zonal congestion management system to resolve transmission congestion. Congestion can occur in any electrical system when the lowest-cost mix of generating plants to serve customer needs cannot be used because transmission lines would be overloaded under that pattern of generation and load. If transmission facilities limit the operation of the optimal set of generation plants, the transmission grid is said to be "congested." Congestion is relieved through rearranging or "redispatching" generation such that the flow of electricity on the grid is altered, and the constraining line is no longer in danger of being overloaded. Generating units that are ordered by ERCOT to lower or increase their output to relieve congestion receive payments to do so from other market participants.

In the ERCOT zonal system, the transmission elements that are most likely to limit the free flow of electricity are identified as "commercially significant constraints" (CSCs), and the transmission grid is divided into congestion zones such that each of the generators and loads within a zone has a similar effect on the CSCs between the zones. In 2001, for example, there were three congestion zones (North, South, and West), and in 2002 a fourth zone was added for the Houston area. In a zonal system, most congestion occurs between zones (zonal congestion), but it can also occur within a zone (local congestion). From July 31, 2001 through May 31, 2002, zonal congestion costs were about $175 million and local congestion costs were about $75 million.

When ERCOT began operation as a single control area on July 31, 2001, the costs for relieving congestion were "uplifted" or spread among market participants on the basis of the market participant's share of the load on the system. This mechanism divorced the costs of relieving congestion from those parties that actually caused the congestion, and provided incentives for market participants to knowingly schedule generation across congested CSCs, knowing that they would likely receive more in payments to relieve that congestion than they would be assessed. The Commission required ERCOT to switch to a direct assignment methodology by the earlier of January 1, 2003 or six months after zonal congestion costs exceeded $20 million. It also required ERCOT to implement a system of transmission congestion rights (TCRs), which would allow market participants to hedge their anticipated congestion costs. The $20 million threshold was reached on August 15, 2001, and direct assignment of zonal congestion and the TCR system were implemented on February 15, 2002. Once direct assignment was implemented, market participants had to exercise greater caution in scheduling across CSCs, and zonal congestion costs were reduced significantly. Interzonal congestion costs totaled $165 million from July 31, 2001 through February 14, 2002. After direct assignment was implemented on February 15, 2002, additional interzonal congestion costs have totaled only $30 million (through September 30, 2002).

In approving the ERCOT Protocols, the Commission also ordered ERCOT to implement direct assignment of local congestion costs if the costs of clearing local congestion rose above $20 million, or to notify the Commission if such implementation was infeasible. This target was reached on March 5, 2002. The Commission's Market Oversight Division (MOD) developed a protocol revision request (PRR) to implement the direct assignment of local congestion costs in the ERCOT market using a fee-based approach that charges or pays generating units in proportion to the operational impact they have on a congested local transmission line. Under this proposal, generating units that increase congestion would pay ERCOT a fee for the congestion, and generating units that reduce congestion would receive a payment from ERCOT.

Market participants have expressed concerns about the approach recommended by MOD, and have proposed alternatives, including implementing locational marginal pricing (LMP), an approach used in other electric markets in the United States. Implementing LMP would require a substantial market redesign for ERCOT. The Commission is currently evaluating the alternative proposals, and anticipates deciding on a proper resolution in early 2003.

b. Protocols Revisions and Enhancements

Since the Commission's approval of the ERCOT Protocols on June 4, 2001, the Protocols have undergone significant enhancement to improve the wholesale market, many pursuant to Commission order:

- In August 2002, $1,000 bid caps for the sale to ERCOT of capacity related ancillary services necessary for reliability were implemented to mitigate the adverse impacts of temporary supply disruptions.
- In June 2002, stricter requirements for generators to adhere to their production schedules were imposed, in order to improve reliability.
- In July 2002, ERCOT began disclosing more market information, thereby increasing the openness (transparency) of the market.
- Also in July 2002, the payment formulas for relieving local congestion costs were reduced in order to better control the costs for this service.
- In November 2002, ERCOT began allowing wholesale suppliers and buyers to trade in ERCOT's real-time (balancing) energy market. Prior to November 2002, all buyers and suppliers were required to submit "balanced schedules," and the balancing energy market primarily existed to permit ERCOT to cover the forecasting errors of market participants.

Market participants and ERCOT are currently discussing how to implement more efficient methods to procure ancillary services necessary for reliability (e.g., two settlement systems and simultaneous optimization). ERCOT is also considering ways to improve the treatment of generators necessary for reliability (reliability must run or "RMR" units). ERCOT has recently entered into several RMR agreements to keep certain power plants in service that are needed for reliability, but whose owners have announced intentions to retire or "mothball" the plants for economic reasons. A total of 47 power generation units at 19 power plants (about 4,000 MW of capacity) were offered to ERCOT for RMR service. ERCOT's analysis concluded that only 16 units at eight plants (about 1,800 MW) were required for system reliability needs. The costs related to compensating generators for RMR service are shared among all market participants. Costs related to RMR service from October 2002 to December 2002 were estimated to be about $32.7 million, and many market participants, as well as the Commission, have raised concerns about both the process used to designate RMR units and the cost recovery granted to the generation owners. ERCOT currently has a task force investigating whether changes to the ERCOT Protocols are needed.

c. Registration and Switching of Retail Customers

The Protocols task ERCOT with the role of the central registration agent in Texas. ERCOT controls and maintains a massive database that includes every electricity-consuming premise in areas open to competition, and is responsible for associating that premise with the customers' chosen REP. As a result, ERCOT is the central point for processing switch requests from customers to a new REP, and has assumed the role of assuring that switches are valid requests by customers and not unauthorized switch requests (slamming).

Texas is unique in the United States in utilizing this central registration system and clearinghouse for retail transactions. Other states typically have required the local utility to process and manage switch requests, leading to concerns regarding favoritism of affiliates and non-discriminatory treatment of retail providers. The central registration system has required significant investments at ERCOT, and requires the ability to interface with the computer systems of the TDUs and REPs in order to process the electronic transactions needed to effectuate switches. ERCOT has developed standard electronic transactions for the electronic transmission of data among REPs, utilities, and ERCOT.

The systems needed for all market participants and ERCOT to efficiently process switch requests were originally not as reliable as intended, and significant work and manual processes have needed to be developed in order to switch customers in the timeframes completed by ERCOT Protocols and Commission rules. Additional versions of software and procedures have been (and will continue to be) needed to resolve many of the issues in the marketplace related to switch requests and related issues. Notwithstanding these problems, the Commission continues to believe that in the long run, once the initial set of problems and gaps in the current system are resolved, a centralized registration, switching, and settlement process will dramatically lower the costs to new entrants into the marketplace, and facilitate the development of the retail market. The problems associated with switching customers (and related technical problems) are discussed in greater detail in Section IV.C.

3. Market Oversight

Texas is also unique in that the monitoring of the market is performed by the Commission instead of a market-monitoring unit at the independent organization. The Commission has performed several reorganizations of its staff in order to address the need for ongoing market oversight of the wholesale and retail markets.

a. Market Oversight Division

PURA § 39.157 mandates that the Commission monitor market power associated with the generation, transmission, distribution and sale of electricity in Texas and gives the Commission the authority to require mitigation of market power. In addition, PURA § 39.155(a) gives the Commission the authority to request any information it needs from market participants to assess market power and evaluate the development of a competitive retail market in the state.

Market monitoring has been a major concern for many market participants in Texas, especially smaller entities and customer representatives. In addition, experience in other markets that have opened to retail electric competition shows that there is a need for market monitoring. In response to these concerns, the Commission created the Market Oversight Division (MOD) in August 2000.

Outside of ERCOT, monitoring of competitive wholesale markets falls under the jurisdiction of the FERC. The FERC oversees markets through the combination of its own recently expanded market monitoring office and market monitoring staff of independent system operators and regional transmission organizations. Texas market participants agreed that market monitoring in ERCOT was an appropriate function for the Commission.

MOD's responsibilities include actively monitoring the activities of market participants to ensure compliance with Commission rules and the ERCOT Protocols and to prevent the exercise of market power and other anticompetitive behavior. MOD investigates market activities as necessary, and actively participates in market design and implementation activities at ERCOT to proactively eliminate market design flaws as they are recognized. MOD staffing currently consists of nine full time employees, and MOD has also been able to rely on the skills of graduate student interns in the Economics and Engineering programs at the University of Texas at Austin. A comparison of the market oversight staffs in the five operating competitive electric markets in the United States compared to MOD is shown in the table below:

Table 8: Comparison of Market Oversight Staffing in Competitive Electricity Markets in the U.S.

Market Monitoring Unit	Market Size (Peak Demand)	2002 FTEs	2003 FTEs	2002 Budget
California ISO	43,000 MW	14	16	$3.0 million
New England ISO	26,000 MW	11	14	$1.9 million
New York ISO	32,000 MW	21	30	$4.8 million
Pennsylvania-New Jersey-Maryland (PJM)	54,000 MW	12	NA	$2.7 million
ERCOT (PUCT MOD)	58,000 MW	9	NA	$0.6 million

SOURCE: 2002 budget figures are estimates provided by each ISO and include the costs of consulting services. Figures for New York include resources for legal enforcement. New York indicates it budget for 2003 will be increased to $6.5 million.

Based on estimates obtained from an independent third party, MOD would be best suited to effectively monitor the market with a budget of $2 million per year. The Commission has recently issued a request for proposals for consulting services to assist MOD in performing oversight of the wholesale electric market in ERCOT. The Commission has requested an exceptional budget item in order to accommodate the additional expenses needed for these services.

b. Retail Market Oversight

The Commission has also recently created a Retail Market Oversight Section in the Electric Division to coordinate monitoring of retail electric market issues. The responsibilities of this section include the monitoring of the day-to-day operation of the retail market in Texas, including monitoring the success of processing switch requests, move-in/move-out transactions, the exchange of meter data needed to bill retail customers, and billing issues that affect retail customers. This section also monitors compliance with Commission rules, transmission and distribution tariffs and the ERCOT Protocols, and actively participates in retail market design and implementation activities at ERCOT. Additionally, this section actively participates in the development of retail market protocols for the areas outside of ERCOT, and oversees the administration of the system benefit fund and low-income discount programs, among other responsibilities.

c. Enforcement

The Commission has also created an Enforcement Section in the Legal Division of the Commission. This section will coordinate formal enforcement actions with MOD, the Electric Division, and the Customer Protection Division and bring actions against market participants for violations of Commission rules, tariffs, and the ERCOT Protocols.

D. DELAY OF RETAIL COMPETITION IN NON-ERCOT AREAS OF TEXAS

1. Non-ERCOT Market Structure

The structure and operation of the wholesale market is notably different outside of the ERCOT region from that which exists in ERCOT. Transmission access and pricing and wholesale generation markets are under the jurisdiction of the FERC, while retail pricing and market operations are under the jurisdiction of the Commission. Accordingly, utilities operating outside of ERCOT are required to provide transmission service and access under a FERC-approved, open-access transmission tariff (OATT). Additionally, ancillary services are generally provided under cost-based rates as well.

Transmission service is provided under the OATTs in two forms: network service, and point-to-point service. Network service is a very flexible service under which a transmission customer[40] can utilize a mix of generation resources to serve its customers. Bundled utilities generally are able to nominate their generation fleet to serve their retail customers under long-term (one-year or more) network service. In the event that a particular generation plant is unavailable due to maintenance or unplanned outages, a utility can redispatch other generation resources in order to serve its customers.

Point-to-point service is a less flexible service that permits individual generation units to serve individual delivery points, generally a wholesale point of delivery such as a municipal utility or an electric cooperative. While point-to-point transmission service is intended to be tradable, transmission customers taking this type of service have had difficulty in the past altering their transmission service if the generating unit they are scheduling becomes unavailable.

Transmission service under the OATTs also has different levels of quality and duration. Often, if long-term network transmission service is unavailable, a transmission customer can obtain shorter-term service, or non-firm (interruptible) transmission service. However, in the event that transmission congestion occurs, these non-firm and shorter-term services are curtailed, and the customers must either find other generation resources that the transmission grid can accommodate, or be assessed the costs of redispatching other generation resources to maintain reliability. There are currently few, if any, provisions in the OATTs that permit transmission customers to manage the risks of these costs.

2. Delays of Competition

Full retail competition in all areas of Texas outside of ERCOT has been delayed either by legislative mandate or order of the Commission. SB 7 delayed competition for the El Paso

[40] Transmission customer typically refers to a utility, electric cooperative, municipally owned utility, power marketer, or generation company. It will also refer to REPs in a competitive retail market.

Electric service area until September 2005, the end of the rate-freeze period resulting from El Paso Electric's bankruptcy proceeding in 1995.

The 77th Legislature delayed competition in the Southwestern Public Service Company (SPS) service area until 2007 at the earliest. The SPS service area, in the Panhandle region of Texas, is a transmission-constrained area, which potentially limits the ability of power generation companies and REPs to serve retail customers. The Legislature required SPS to provide an analysis to the Electric Utility Restructuring Legislative Oversight Committee regarding the need for additional transmission infrastructure that would make that region's transmission grid comparable to the transmission grid in ERCOT, as well as provide information on plans to interconnect with other power regions. If SPS chooses to participate in customer choice after 2007, it must file a plan with the Commission regarding the mitigation of market power and transmission expansion needed to achieve full customer choice.

During the summer of 2001, it became apparent that very few customers in the SWEPCO and Entergy service areas had been able to participate in the pilot project, in large part because of the lack of REPs operating in these areas. In August 2001, PUC staff initiated contested case proceedings to determine the readiness of these areas for full customer choice.

The Commission delayed the start of full customer choice for Entergy, SWEPCO, and the small portion of WTU that is located within the Southwest Power Pool region.[41] Based on the evidence presented by parties in those proceedings, and a non-unanimous settlement achieved by most of the parties to the Entergy proceeding, the Commission found that these areas were unable to offer fair competition and reliable service to all customer classes on January 1, 2002 pursuant to PURA §§ 39.103 and 39.104(a).[42]

The Commission ultimately delayed competition for the Entergy and SWEPCO service areas, in large part due to three sets of issues:

1. A lack of independence in the administration of transmission service and uncertainty about the market rules for these areas;
2. A lack of testing for the technical systems needed to accommodate retail choice; and
3. A lack of necessary market institutions and a lack of open and non-discriminatory access to the transmission grid.

---

[41] *Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas within the Southwest Power Pool*, Docket No. 24468, Order on Rehearing (Feb. 1, 2002); *Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas within the Southeastern Electric Reliability Council*, Docket No. 24469, Order (Dec. 20, 2001).

[42] PURA § 39.103 requires the Commission to delay customer choice in a power region if it determines that region is unable to offer fair competition and reliable service to all customer classes on January 1, 2002. PURA § 39.104(a) provides that the Commission may base its determination on the evaluation of the pilot projects and other criteria deemed appropriate.

a. Independence

In the case of SWEPCO and for the small portion of WTU that is outside of ERCOT, the transmission tariff is currently administered by the Southwest Power Pool (SPP), an independent organization governed by a stakeholder board of transmission providers, power marketers, and generating companies. Entergy's transmission division administers the tariff for the Entergy service territory. While the SPP does provide a level of independence in administering the transmission tariff of SWEPCO, it became clear during the course of the contested case proceedings that REPs and independent power generation companies did not have sufficient confidence that Entergy's administration of its transmission tariff would provide truly equal access.

This lack of independence stems in part from the delays related to the creation and FERC approval of Regional Transmission Organizations (RTOs) in the Southeast and South-Central areas of the United States. Because RTOs will ultimately perform many of the functions and responsibilities necessary to support viable and sustainable wholesale and retail competition (much in the way ERCOT performs this role in most of Texas), the uncertainty regarding FERC's approval of RTOs (and related market design and systems development issues) in the non-ERCOT areas of Texas has likely led to a reluctance by REPs to invest in the systems needed to serve customers in these areas.

b. Systems Testing

Because no customers or REPs participated in the pilot program in these service areas, there were serious concerns that the systems to accommodate retail choice (*i.e.*, settlement, retail billing, the provision of meter data, etc.) had not been adequately tested.

c. Open Access under the OATT

While the OATTs of Entergy and SWEPCO had been slightly modified in an attempt to accommodate retail competition in Texas, it became evident during contested case proceedings before the Commission that the tariffs, in their current forms, may not truly provide for open and non-discriminatory access to the transmission grid in a workable form for all retailers and power generators in a competitive retail market.[43] Concerns were raised by several parties that Entergy's (and SWEPCO's) affiliated REP and power generation companies may in fact be guaranteed network transmission service when no other REP or independent generation company may be able to obtain comparable access, even under the truly independent administration of the transmission tariff. In short, while the OATTs may be adequate in accommodating wholesale competition, they do not appear to be able, in their current form, to adequately accommodate retail competition.

[43] *See Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas within the Southwest Power Pool*, Docket No. 24468, Order on Rehearing at 4-5 (Feb. 1, 2002). *Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas within the Southeast Electric Reliability Council*, Docket No. 24469, Final Order (Dec. 20, 2001).

Notwithstanding the decision to delay full market opening, the Commission remains committed to customer choice in these areas. The pilot projects were extended indefinitely for Entergy and SWEPCO. In addition, Commission proceedings were established to develop the necessary steps to transition to full customer choice and to monitor market structures and conditions.[44] The non-unanimous stipulation approved by the Commission in the Entergy proceeding initially contemplated a September 1, 2002 start date for retail competition. However, Entergy, other market participants, consumer representatives, and the PUC staff could not achieve resolution on many of the key issues discussed above, in part due to ongoing proceedings at FERC relating to development of a RTO in the southeastern United States. At this point in time, it appears unlikely that a FERC-approved RTO will be fully functional for the Entergy service area until January 2004 at the earliest. As a result, in January 2003, parties are expected to file their proposals for an "interim solution" by which retail competition in the Entergy area could proceed without a functional RTO.

Additionally, Entergy, other market participants, consumer representatives, and PUC staff are currently engaged in a collaborative stakeholder process to develop market rules for retail competition in the Entergy service area. These proceedings are currently focused on developing market protocols for the Entergy service area similar to those established in ERCOT, and the stakeholders and PUC staff is currently attempting to remedy the existing deficiencies in the OATTs. The stakeholders have completed the first round of these discussions and the second round is scheduled to be completed in January 2003, at which time the Protocols and any remaining disputes will be brought before the Commission for decision.

While the stakeholders are attempting to create protocols consistent with the current OATTs (thereby likely eliminating the need for FERC approval), it remains possible that the Commission may desire Entergy (and SWEPCO) to request changes to its OATT before the Commission will permit the area to open to retail competition. If Entergy and/or SWEPCO or the FERC does not make such changes, or if the Commission believes that full and fair retail competition cannot be achieved in the area, the Commission has the authority to continue to delay competition and establish new bundled, regulated rates for Entergy and SWEPCO, pursuant to the ratemaking procedures outlined in Chapter 36 of PURA.

3. FERC Standard Market Design

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) and proposed a series of sweeping changes intended to provide a single set of clear rules to govern the wholesale electric industry and to remedy undue discrimination in the provision of transmission service (also known as standard market design, or SMD).

---

[44] *See Southwest Power Pool Market Readiness Implementation Project*, Project No. 24869 (pending). *See also Project to Develop Market Protocols in the Portion of Texas within the Southeastern Electric Reliability Council*, Project No. 25089 (pending).

The NOPR includes proposals to:

- Eliminate the distinctions between network service and point-to-point service, and instead establish a single, flexible network access transmission service under which all customers (*i.e.*, wholesale, unbundled retail, and bundled retail customers), would take service;
- Require transmission systems to be operated by an independent entity;
- Adopt locational marginal pricing (LMP) for congestion management, and provide for tradable financial Congestion Revenue Rights as a means to hedge the risks associated with congestion;
- Establish procedures to monitor and mitigate market power, including a $1,000 per MWh bid cap in spot markets;
- Establish procedures to ensure long-term adequacy of generation, transmission, and demand-side resources;
- Alter the rate design of transmission cost recovery mechanisms;
- Facilitate day-ahead and real time markets, but rely primarily on bilateral contracts for generation sales; and
- Create a formal role for states to participate in the decision-making processes of regional transmission organizations or other regional entities.

The Commission generally believes that the SMD's proposed reforms will make wholesale markets outside of ERCOT fairer and more efficient, as well as address many of the issues that have impeded the development of competitive retail markets in areas of Texas outside of ERCOT. The Commission is continuing to evaluate the specifics of the NOPR and submitted comments to FERC in November 2002. The Commission will provide supplemental comments to FERC in January 2003.

E. CUSTOMER EDUCATION CAMPAIGN

PURA § 39.902 requires the Commission to develop and implement an educational program to inform customers, including low-income and non-English-speaking customers, about changes in the provision of electric service resulting from the opening of the retail electric market.

1. Overview of the Education Campaign

Since its inception in February of 2001, the "Texas Electric Choice" campaign has endeavored to educate Texans about the changes and choices in the retail electric market. In year one (February to August 2001), the campaign focused on awareness – that electric competition was coming to Texas on January 1, 2002, and that customers could participate in a pilot program during the summer of 2001. During year two (September 2001 to August 2002), the campaign shifted its focus to educating Texans about Electric Choice and their choices in electric providers.

The integrated education campaign uses a number of vehicles, in both English and Spanish, to reach and educate the public. A summary of each of these methods is included below.

a. Key Campaign Objectives

The following are the objectives for the education campaign:

- Build awareness of changes in the Texas retail electric market.
- Educate all eligible customers about their choices in electric providers.
- Underscore the Texas PUC's involvement in, and oversight of, the restructuring process.
- Provide as many points of contact to the education campaign (website, answer center, radio and TV advertising, news stories, printed educational materials, community events, etc.) as possible within budgetary parameters.

b. Key Campaign Messages

Key messages are the main points that are communicated to the public. These broad statements are backed up by sub-messages elaborating the campaign information.

- Electric choice is working for Texas.
- Be an informed customer.
- The PUC will continue to protect customer rights.
- The transition to a competitive electric market takes time.
- Learn how to shop for electricity.
- Compare offers from Retail Electric Providers (REPs) and explore your options.

c. Key Campaign Vehicles

Texas Electric Choice is a fully integrated communications campaign that uses a variety of communications vehicles to reach customers eligible for electric competition. These methods include paid advertising, a website, an answer center, newspaper inserts, educational literature, community-based outreach, and media relations.

Paid Advertising. Advertising is the best way to reach mass audiences, helps to raise awareness of the issues surrounding electric competition, and plays a leading role to support customer education efforts such as grassroots outreach, media relations, and educational literature.

In years one and two, paid advertising activities encompassed television, radio, print, outdoor advertising, and the Internet. The campaign launched TV advertising, radio ads, and print ads in the spring of 2001 to raise awareness that electric competition was coming to Texas. In the summer of 2001, the campaign produced a public service announcement (PSA) differentiating Texas's electric restructuring plan from California's much-publicized problems. Radio and print ads were used throughout the fall and winter of 2001 and the spring of 2002 to continue the campaign messages. In the summer of 2002, the television PSA and radio advertising were updated to reinforce the idea that Texas is doing electric restructuring right.

In year three, significant television advertising surrounded the direct-mail distribution of the comprehensive *Power Guide to Electric Choice* to the approximately five million retail customers eligible for competition. In addition, selected radio, print (including minority publications), and outdoor advertising (billboards) supported the television messages.

Website. The campaign's website, www.powertochoose.org, and its Spanish counterpart, www.poderdeescoger.org, are a vital part of the customer education process. These sites allow customers to learn about electric competition at their own pace, as well as providing apples-to-apples rate comparisons in their specific service territory. Both sites are continually updated with the latest news and events surrounding the campaign.

- Unique Visitors: 1,295,000 (Feb. 2001-Dec. 2002)
- Hits: 60,000,000 (Feb. 2001-Dec. 2002)
- Downloads of Power Guide: 40,500 (Feb. 2001-Dec. 2002)

Answer Center. The campaign provides a Texas-based toll-free, bilingual answer center, 1-866-PWR-4-TEX (1-866-797-4839), as a way to give customers another point of contact with the campaign. Customer service representatives are available six days a week, and an automated system serves customers seven days a week. Customers can ask questions, learn which REPs are serving their areas, and request educational materials.

- Total Calls: 325,000 (Feb. 2001-Dec. 2002)
- Representative-Assisted Calls: 224,000 (Feb. 2001-Dec. 2002)
- Spanish-language Calls: 16,000 (Feb. 2001-Dec. 2002)

Newspaper Inserts. The campaign has distributed two different sets of educational materials via Sunday newspapers across the state. In year one, a four-page introductory piece was included in two distributions; in year two, the *Power Guide to Electric Choice* was distributed in three waves across the state.

Educational Literature. Brochures, fact sheets and other educational materials are distributed via a network of more than 7,500 community-based organizations, including energy assistance service providers under contract with the Texas Department of Housing and Community Affairs. Materials are also distributed via direct mail, e-mail, at campaign events, and via the website and Answer Center. Fact sheets on a number of topics are easily updated and distributed to the public in our outreach efforts.

- Power Guide: 250,000 (30,000 via web)
- Low-income brochures: 175,000
- Texas vs. California: 350,000
- Fact Sheets: 250,000
- Texas Electric Choice Educational Video: (In Production)

Community-Based Outreach. The campaign has participated in more than 2,700 local community events since February 2001. Workshops were conducted by Commissioners, PUC staff, and the Texas Electric Choice Campaign. Grassroots and community-based organizations (CBOs) provide an exceptional communication channel for distributing printed materials, and for providing speaking venues and third-party endorsements by key community leaders. These organizations also provide an integral link to the low-income community.

In addition, presentations specifically addressing low-income concerns, including LITE-UP[45] applications, were given at events sponsored by the Texas Department of Housing and Community Affairs and by low-income energy assistance services providers.

- African-American: 557 CBO events
- Asian: 295 CBO events
- Hispanic: 250 CBO events
- All markets: 1,600 CBO events

For year three, the Commission will continue a regional approach to serve the needs of community-based organizations. The Commission's primary focus will be ongoing outreach to statewide organizations such as the Texas Realtors Association, Chambers of Commerce, Area Councils on Aging, United Way agencies, low-income energy assistance service providers, and minority Chambers of Commerce.

2. Evaluation of the Effectiveness of the Campaign

The Commission retained The Center for Research & Public Policy (CRPP) to survey Texas electricity consumers in order to help the Texas Electric Choice campaign evaluate and adjust the consumer education campaign to provide the greatest impact on consumer knowledge about electric choice. CRPP provided a report to the Commission summarizing the results from surveys conducted August 12–19, 2002.

[45] *See* Section III.H.2 for more discussion of the LITE-UP program.

Highlights of the report include:

- Two-thirds of residential customers (66.8%) and 79.6% of businesses have heard, read or seen something about competition or deregulation.
- Residential respondents who reported knowing a "great deal" or a "moderate amount" about electric competition in Texas increased from 15.3% in 2000, to 23.3% in March 2001, to 34.3% in August 2001, and to 62.0% in August 2002. Among business leaders, 55.2% replied that they know a great deal or a moderate amount.
- Almost two-thirds of residents (64.0%) and 57.6% of business leaders reported that their view toward electric competition is very or somewhat positive. Among residents, this percentage is up from 52.0% in March 2001 and 48.3% in August 2001. However, the percentage is down slightly from 66.8% in 2000.
- Residential customers who hold negative views of electric competition do so because they do not see the benefit, see insufficient amount of savings, are concerned about reliability, are not familiar with the REPs, or find the process too confusing.
- Three quarters of all residential (75.3%) and business (72.8%) respondents stated that they are very or somewhat interested in the idea of choosing a retail electric provider. Among residents, the percentage remained consistent with 77.2% in 2000, 75.6% in March 2001 and 71.8% in August 2001.
- Sixteen percent of residents and 14.1% of business leaders reported that they would switch for monthly savings of $1.00 to $20.00 off their typical monthly summer bill.
- Growing numbers of residential respondents —11.9% (up from 6.9% in August 2001) — replied that they could make an informed decision today regarding their choice of a retail electric provider.
- Fewer respondents today, 37.4%, stated that the decision process to choose a new retail electric provider is very easy or somewhat easy. This percentage is down from 45.3% in 2000 and 41.5% in March 2001. Among business leaders, 48.1% stated that the decision process is very or somewhat easy.
- A large majority (77.9%) of residential respondents reported that they expect their bills to be easier to understand (19.4%) or remain easy to understand (58.5%) with the introduction of electric competition. Another 14.3% reported that they expect their bills to remain difficult to understand (6.1%) or become harder to understand (8.2%).
- A significant percentage, 68.8%, of residents (47.9% among business leaders) recalled seeing stories on electric competition, Texas Electric Choice, or deregulation of electric utilities.
- As a result of these stories, 49.9% of residents and 66.2% of business leaders said their interest levels regarding retail competition have increased or remained high.
- While the news stories did not change the views of 46.4% of residents regarding competition, 23.0% said the stories resulted in a positive change, while 25.9% replied that their view has become more negative.
- Among business leaders, views did not change for 47.3% of those who recalled seeing stories. Another 19.9% said their views on competition improved or changed positively, while 16.9% said they now hold more negative views as a result of the stories.

F. RETAIL ELECTRIC PROVIDER (REP) CERTIFICATION AND AGGREGATOR REGISTRATION

1. REP Certifications, Revocations, and Withdrawals

In order to serve retail customers in Texas, a REP must be certified by the Commission and meet certain financial and technical requirements. REPs are responsible for complying with a significant number of customer service and customer protection obligations, submitting customer switch requests through ERCOT, buying and scheduling wholesale electricity, billing and collecting from retail customers, and paying their wholesale providers and TDUs.

The standards for REPs vary based on the class of certification sought, either by geographical service area or specific large electric customers. Generally, a REP must show that it has the technical and financial ability to meet all of its obligations in the market, or show that it has contracted with a third party to perform those functions. A REP can meet the financial requirements to be certified by having either (1) an investment grade credit rating; (2) assets in excess of liabilities of $50 million or (3) unused cash resources of at least $250,000 (with those resource requirements increasing as the REP serves more customers). The Commission's Financial Review staff actively monitors the compliance of REPs with these financial requirements.

The Commission has certified a total of 54 REPs since December 2000, with four other certifications pending. In addition to affiliated REPs unbundled from the integrated utilities, the types of business that have been certified as REPs in Texas include a wide range of existing companies expanding into new business and markets, as well as new companies formed specifically to market retail electricity service in Texas.

Several REPs are affiliated with utilities in other states, such as Constellation New Energy, PG&E Trading, and Sempra Energy. Others, such as Green Mountain Energy, ACN Energy, and Strategic Entergy offer retail electricity service in other states open to competition, and have expanded to Texas. Centrica, PLC, which does business in Texas under the name Energy America, is a British company that offers retail electricity and natural gas service in the United Kingdom and Canada, as well as in other US states.

A few companies that own power generation assets in Texas have also created affiliates that have been certified as REPs. These companies include Calpine, Dynegy, Tenaska, and BP Energy. Several entities that have traditionally been customers to the bundled utilities, such as TXI and Occidental, have also created REPs to serve their load, as well as potentially other customers.

Other REPs, such as GEXA, Utility Choice, and Texas Commercial Energy are new companies formed specifically to offer retail electricity in Texas. A complete list of REPs is included in Appendix 4.

a. Suspensions and Revocations

Shell Energy Services. In September 2001, Shell Energy Services announced that it was pulling out of the Texas electric retail market because the pace of electricity deregulation across the U.S. had slowed substantially.[46] Shell filed its formal application to suspend its REP certificate, and Shell customers were returned to their utility and were allowed to choose another REP. In January 2002, the Commission granted the suspension of Shell's REP certificate.

Enron Energy Services and Enron Power Marketing. Enron Energy Services (EES) and Enron Power Marketing, Inc. (EPMI) were wholly-owned subsidiaries of Enron Corporation and were certified as retail electric providers in Texas. Upon Enron's bankruptcy filing, Commission staff requested that Enron provide proof of the capability of EES and EPMI to operate as REPs, and their ability to meet the technical and financial requirements for certification. Although EES had contracted with a large number of commercial customers, those customers were never switched to EES.

In response to concerns over EES's failure to provide proof of its capability to operate as a REP in Texas, Staff filed a petition to suspend and/or revoke the REP certificates for EES and EMPI, and EPMI subsequently agreed to voluntarily withdraw its REP certificate. The Commission approved a procedure to allow EES to transfer its customer contracts[47] to another REP, subject to approval by the bankruptcy court, and prohibited EES from marketing to or serving customers in Texas pending the sale. The transaction ultimately fell through, and the Commission revoked EES's REP certificate shortly thereafter.

The New Power Company. The New Power Company was certified as a retail electric provider in December 2000, and served approximately 80,000 customers (mostly residential, with some small commercial) in the Reliant and Oncor (TXU) service areas.

Due to New Power's affiliation with Enron Corporation, Commission staff initiated contact with New Power to verify that it had the financial resources to operate as a REP in Texas and had the ability to meet the technical and financial requirements for certification following the Enron bankruptcy filing. In December 2001, New Power began submitting detailed monthly financial reports to Commission staff, and held meetings with staff to describe New Power's business plans and financial status.

After several unsuccessful attempts to merge with other REPs or to sell the customer contracts to another REP, New Power entered into agreements with TXU and Reliant to transfer New Power customers to these other REPs in lieu of transferring the customers to the POLR. New Power has requested that it be permitted to withdrawal its REP certificate. The Commission has approved the withdrawal on an interim basis, pending New Power fulfilling its remaining obligations to retail customers in Texas.

---

[46] Shell Energy Services, L.L.C., "Shell Energy Withdraws From Ohio and Texas Electric Power Markets," news release (Sept. 4, 2001).

[47] On March 12, 2002, EES reported that it had 12,702 customer contracts and that 4,856 customers had opted out.

These remaining obligations include:

- Compliance with Commission rules and state law for all remaining bills issued;
- New Power's submission of samples of issued bills to Commission staff and the Office of Public Utility Counsel (OPUC) for inspection;
- New Power's compliance with its agreement to not assess late fees or penalties if bills are not paid on a timely basis;
- New Power's compliance with its agreement to notify customers that previously issued bills may not have been fully compliant with Commission rules;
- New Power's compliance with its agreement that any sale of remaining accounts receivable to a collection agency will include a provision that the purchaser may not report information to credit bureaus that may negatively impact the customer's credit rating;
- Satisfactory resolution of all pending and future customer complaints;
- New Power's compliance with its agreement to retain call center and complaint response capability for 61 days after issuance of its last final bill; and
- Compliance with certain agreements related to providing customers with the economic value of incentives they were promised to encourage them to switch to New Power.

2. Aggregator Registrations

Generally, the role of an aggregator is to join two or more customers together and negotiate a rate and/or packages of service for the group of customers. As such, the aggregator acts as a buyer's agent on behalf of customers, and should not represent the interest of a REP. Unlike a REP, an aggregator does not take title to the electricity.

Under Commission rules, aggregators may be registered under five classes:[48]

- **Class I** aggregators join at least two voluntary customers as a single purchasing group. They may not include municipalities, political subdivisions, or political subdivision corporations.
- **Class II.A** aggregator is a person who joins municipalities, political subdivisions or both.
- **Class II.B** aggregator is a political subdivision corporation that aggregates political subdivisions.
- **Class II.C** aggregator is a public body that aggregates citizens who affirmatively request such services.
- **Class II.D** aggregator is authorized by a political subdivision to act as administrator of a citizen aggregation project.

As of October 2002, there were 131 aggregators registered with the Commission. The majority (122) carry a Class I registration. About one-third carry one of the Class II classifications. Approximately a dozen entities registered under a classification other than Class I, primarily in the Class II.A and II.B categories (persons that aggregate municipalities or political subdivisions or political subdivision corporations that aggregate political subdivisions).

[48] Persons may also register under a combination of these aggregator classes.

Other aggregators planned to aggregate all types of customers, ranging from residential and commercial to municipalities and political subdivisions.

The annual reports filed by aggregators, however, reveal far less diversity in types of customers being served under aggregation projects. About half of the 73 aggregators that have filed reports were unable to develop successful aggregation projects and report having no customers. The majority of the entities that did develop aggregation projects served primarily commercial and industrial customers, and political subdivisions such as groups of cities and/or schools. However, as discussed in Section IV.A.2, these aggregators appear to have been able to negotiate significant savings for their clients.

G. IMPLEMENTATION AND RESULTS OF PILOT PROJECTS

Seven utilities implemented pilot projects during 2001, which permitted up to 5% of electric load within each utility's service area to choose their electricity provider in advance of full retail competition. These utilities were Central Power and Light Company (CPL), Entergy Gulf States, Inc. (Entergy), Reliant Energy HL&P, Southwestern Electric Power Company (SWEPCO), Texas-New Mexico Power Company (TNMP), TXU Electric Company (TXU), and West Texas Utilities Company (WTU). Collectively, the utility pilot projects were known as the Texas Electric Choice Pilot Project (or pilot project).

The intent of the pilot project was to set up systems and processes for the market as a whole, and then to use the pilot project as an arena to troubleshoot those systems and processes. The pilot project was also a vehicle used to inform customers about how and why to participate in the new competitive electric market. Finally, it served as an important tool to evaluate the ability of power regions to offer customer choice.

While the official start of the pilot project was June 1, 2001, many activities began well before that date, such as the development of market rules and protocols, the design and testing of computer and communications systems, and customer education. As early as February 2001, customers began signing up to participate in the pilot project. The pilot project was phased-in to carefully monitor the switching of customers from the incumbent utility to competitive REPs. REPs began submitting requests to switch customers on the June 1, 2001 scheduled start date but did not begin to flow power to customers until July 31, 2001.

1. System Development and Testing

An essential activity to prepare for the pilot project and full market operations was the development and testing of computer and communications systems. These systems are a key element of the new competitive market in Texas. ERCOT, REPs, utilities, and other entities deployed systems and software within a remarkably short period of time—only two years passed from the time SB 7 was signed into law until the pilot project began. The ERCOT systems were installed in late 2000 and configured with customer information up until June 1, 2001.

Business processes for both the pilot project and full market operations were tested by ERCOT and market participants through an independent, third-party testing administrator.[49] The purpose of testing was to replicate the flow of electronic transactions between REPs, TDUs, and ERCOT that were necessary to support operations in the competitive market (*i.e.*, switching providers and invoicing), and then identify and resolve any problems. Testing was conducted

[49] The third-party testing administrator performs several functions, including coordination of testing among market participants, performing architecture and transaction analysis, record keeping, dispute resolution, and market reporting. Prior to full market opening, market participants decided that it would be best for ERCOT to assume this testing function based on cost, value, and the recurring nature of testing. To retain independence, the testing administrator reports outside of the typical ERCOT structure.

in stages to allow for manageable and controlled progression through all the various testing scripts. Testing proved to be a valuable tool to identify and troubleshoot system problems.

2. Pilot Implementation Working Group

The Pilot Implementation Working Group was created as part of the Commission's pilot project rule (P.U.C. SUBST. R. 25.431) to resolve technical and operational issues that arose during implementation of the pilot project and to make recommendations to the Commission as necessary. The Commission ruled on policy issues and any technical issues that could not be resolved through consensus of the working group.

The group started out with a formal committee structure consisting of 11 individuals representing specific interests, including Commission staff, ERCOT and non-ERCOT utilities, the Office of Public Utility Counsel, REPs, aggregators, consumer representatives, ERCOT and the Southwest Power Pool. Shortly after adopting the pilot project rule, the Commission appointed the members to the working group.

The working group was instrumental to the success of the pilot project. A key factor was the group's ability to respond to emerging issues—many of which were never contemplated when the rule was written. While the rule was very detailed, there were still many provisions that had to be interpreted and more fully defined as the pilot was implemented. The ability to adapt the group's process to respond to changing circumstances was also important to ensure the group's time was used efficiently and effectively.

3. Customer Enrollment and Switches

The customer enrollment process during the pilot project was not a single action, but was, instead, a sequence of events. This section discusses key developments related to the customer enrollment and switching processes during the pilot project.

a. Pre-June 1: Customer Sign-ups and Lottery

Customer sign-ups for the pilot began on February 15, 2001, well in advance of the June 1 start date. Residential customer enrollments were accepted on a first-come, first-served basis. Non-residential customers could sign up prior to March 15 for a lottery, which was held for all over-subscribed classes. Customers selected in the lottery had until May 10 to negotiate contracts with REPs. Any remaining load after that date was available on a first-come, first-served basis until the cap was reached.[50]

[50] This applied to non-aggregated load. The 1% set-aside for aggregation was reserved until May 31 for non-residential classes and June 15 for the residential class; after those dates, the remaining load was added to the total load available for that class (*i.e.*, 5% cap).

b. Post-June 1: Switching Activities

The pilot project was phased-in to allow ERCOT to monitor customer switches carefully. REPs began submitting switch requests to ERCOT on June 1, 2001. However, power from the REPs did not begin to flow to customers until July 31, 2001, when ERCOT transitioned to single control-area operations.

A "ramp-up" plan was developed to gradually increase the number of switches that REPs could submit to ERCOT in a given day. This was done to allow ERCOT to monitor and manually correct transaction errors. Initially, each REP was allowed to submit to ERCOT only two switch requests per day per TDU area. The two-switch limit was imposed from June 1, 2001 through the first part of August. Over time, as the success of switch transactions improved, the permitted number of switch requests was gradually increased.[51]

By mid-September 2001, ERCOT processed a large number of switch requests, thereby eliminating the queue of customers waiting to be switched. During September 2001, ERCOT processed an average of 3,420 switch requests per day, the highest production in any month during the pilot. Unrestricted processing continued thereafter. Market participants, ERCOT, and the Commission continued to monitor the performance of switches and other retail transactions throughout the pilot project.

4. Customer Participation

At the end of the pilot project, over 115,000 customers had enrolled in the pilot project to be switched to a competitor of the incumbent utility. Approximately 90% of these customers were residential, 9% were small non-residential (peak demand less than one megawatt), and 1% were large non-residential (peak demand over one megawatt).[52]

Customer participation in the pilot project varied widely by customer class, utility service areas, and geographic regions. Some areas, notably the Houston and Dallas-Fort Worth metropolitan areas, had a significant proportion of customers that choose to receive their power from a REP. In contrast, no customers switched to REPs outside of the ERCOT region.

a. Residential Participation

At the December 31, 2001 conclusion of the pilot project, over 100,000 residential customers had enrolled. The following table provides the number of residential customers that contracted with a REP and the percentage of the 5% cap reached in each service area.

---

[51] ERCOT systems are designed to process approximately 21,000 switch transactions daily.

[52] This distribution is calculated on a per-customer, rather than a load-share basis.

Table 9: Residential Customers Enrolled in the Pilot (December 31, 2001)

Company Name	Total Eligible Pilot Customers	Total Enrolled	% of Participation Cap
Central Power & Light Company	28,764	2,761	10%
Southwestern Electric Power Company	6,745	0	0%
West Texas Utilities Company	7,549	1,669	22%
Entergy Gulf States, Inc.	15,067	0	0%
Reliant Energy HL&P	75,313	39,985	53%
Southwestern Public Service Company	10,602	0	0%
Texas-New Mexico Power Company	7,963	1,378	17%
TXU Electric Company	113,295	56,871	50%
TXU SESCO	1,767	9	1%
Total Residential Participation		102,673	

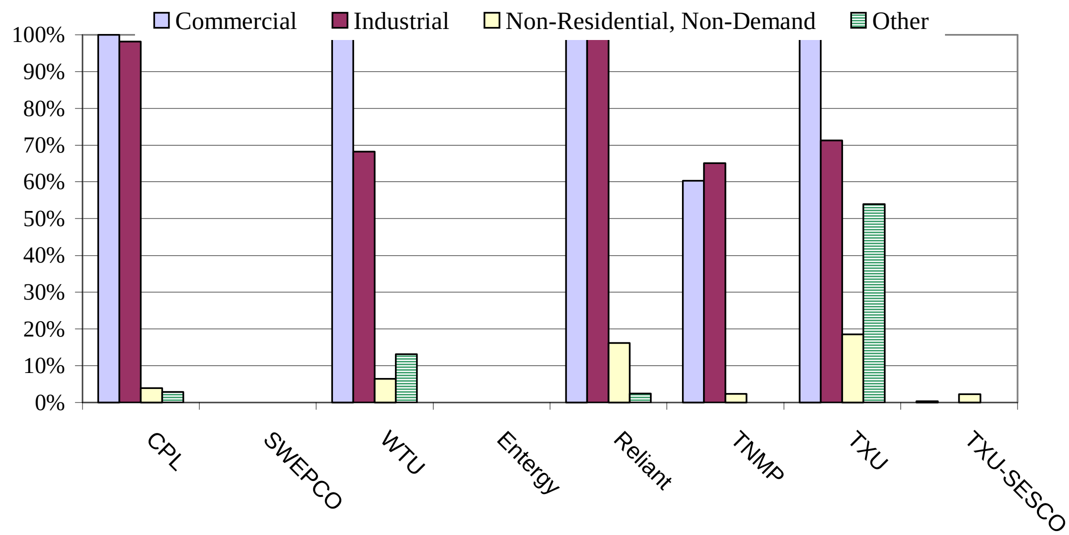
SOURCE: Data filed in Project 22834.

b. Non-Residential Participation

There was considerable interest among non-residential customers for the pilot project. Each utility held a lottery for at least one of the non-residential customer classes, even in the case of SPS, Entergy, and SWEPCO, which ultimately had no customer contracts with REPs. For both the commercial and industrial classes, considerably more load applied for the lottery than was available to participate in the pilot. For example, within HL&P's and TXU's (now Oncor) service areas, about seven times the load available in the industrial class applied for the lottery.

Of the total load available for the pilot within each non-residential class (*i.e.*, 5% cap), the percentage of electric load that contracted with a REP is shown in the figure below. The commercial class was fully subscribed in the CPL, WTU, HL&P, and TXU service areas. The industrial class was more than 60% subscribed in all the utility service areas within ERCOT, except for the TXU-SESCO area.

Figure 7: Percentage of 5% Cap Contracted with REP by Non-Residential Class and Service Area (December 31, 2001)



SOURCE: Data filed in Project No. 22834.

5. Technical Problems

Common technical problems experienced during the pilot project related to switching retail customers included data quality problems, programming defects, connectivity issues, and system capacity constraints.

Throughout the implementation of the pilot project, the electronic transaction codes, particularly those related to customer registration ("814s") and usage information ("867s"), and other technical jargon were used extensively by not only the market participants, ERCOT, and Commission staff, but also the Commissioners themselves. A proficiency in this new "language" was necessary to resolve the major technical problems experienced during the pilot project. A complete list of the electronic transactions used in the market and the associated transactions codes are included in Appendix 5. Market participants also communicated electronically via other means, including ERCOT's web-based portal.

The pilot project was a necessary and critical component of the transition to customer choice in Texas. Market participants and the Commission were actively involved in ensuring that the systems and processes to support customer choice were working efficiently. While there were technical glitches and other challenges, the pilot project achieved its stated purpose by providing an opportunity to identify and resolve problems associated with the new market structure, processes and systems. Collaboration among stakeholders was essential to the resolution of many difficult technical and operational issues. Not all issues were resolved prior to full market opening and market gaps remain. Nonetheless, the pilot project ultimately facilitated a smoother transition to customer choice in the ERCOT region on January 1, 2002 than would have occurred absent the pilot program.

While a delay of full retail competition and continuation of the pilot project could have provided additional time to test and fix the systems that have continued to have operational issues, it is likely that many of the issues that the market and Commission have continued to address during 2002 would not have appeared until full market opening. Furthermore, a delay of competition would have required customers, retail providers, and power generators to renegotiate contracts that had been executed assuming a January 1, 2002 start date. After consideration of all of these factors, the Commission ultimately determined that it was appropriate to move forward with full competition on January 1, 2002.

As discussed in Section III.D, it also became evident through the pilot project that the areas outside of the ERCOT region were not ready to proceed with full customer choice on that date. Continuation of the pilot project in the non-ERCOT areas will provide an opportunity to monitor the markets closely and to ensure that sufficient market structures and conditions exist in those areas prior to moving to full customer choice.

H. ADMINISTRATION OF THE SYSTEM BENEFIT FUND

The System Benefit Fund created by SB 7 was designated to fund four programs:

- An electric rate discount for low income customers (10%-20%), also referred to as LITE-UP (Low-Income Telephone and Electricity Utilities Program);
- A targeted low-income energy-efficiency program administered by the Texas Department of Housing and Community Affairs (TDHCA);[53]
- Appropriations to the Commission for customer education programs[54] and to the Commission and Office of Public Utility Counsel (OPUC) for administrative costs; and
- Compensation for school districts for losses in taxes due to lower property values of the utilities' assets directly caused by the electric restructuring.

Since 2001, the Commission has focused on the practical implementation of the low-income discount. The Commission has awarded a contract to a third-party administrator to develop and operate the computer matching system used to identify low-income customers.

1. SBF Revenue and Expenditures

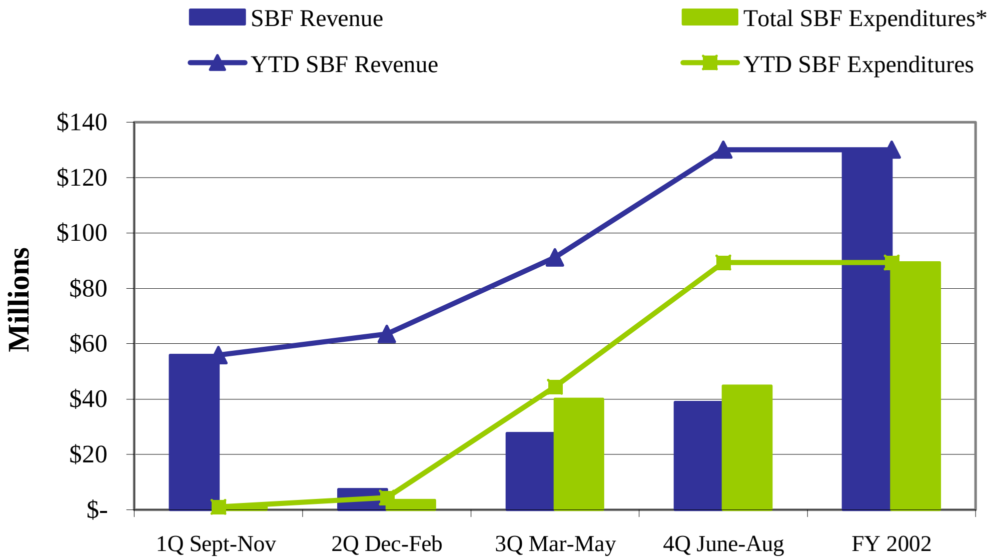
The system benefit fee went into effect on January 1, 2002 as a non-bypassable charge collected by the transmission and distribution utilities (TDU). Prior to this date, investor-owned utilities were directly assessed a fee sufficient to cover expenditures from the fund. The TDU is responsible for submitting the fees to the Texas Comptroller of Public Accounts. The graph below illustrates the revenue and expenses that have been reported for fiscal year 2002.

---

53 Information on TDHCA's energy efficiency programs can be found at www.tdhca.state.tx.us.

54 The Texas Electric Choice customer education campaign is discussed in Section III.E of this report.

Figure 8: System Benefit Fund Revenue and Expenses for FY 2002



SOURCE: PUC Fiscal Services Analysis.

Total revenue into the SBF was approximately $130 million for fiscal year 2002. Expenses out of the fund were approximately $89 million for expenditures related to the low-income discount, customer education, Commission and OPUC administrative costs, TDHCA weatherization programs, and compensations for school funding loss.

Though revenues are currently greater than expenditures, the Commission believes the current balance is needed to ensure the fund's ability to make payments required by the appropriations law. Expenditures for TDHCA are expected to grow from $7.1 million in fiscal year 2002 to $10 million in fiscal year 2003.[55] Additionally, as of August 2002, approximately 616,000 customers were enrolled in the low-income discount program. During the early part of 2002, enrollment was lower than this level, resulting in fewer discounts given in those months than is expected to occur on an ongoing basis. The Commission expects that enrollment will remain at the current level or increase for the remainder of fiscal year 2003. The low-income discount program is discussed further in Section IV.A.3 of this report.

A more significant issue is difficulty in precisely predicting the amount of funds that will be needed to meet required appropriations. While the Commission can estimate the funds needed, the actual expenditures are dependent on factors such as the growth rate of both the low-income population as a whole, and more critically, the number who enroll in the program and the weather (the hotter the weather in the summer, the greater the amount of consumption and customers' bills, and correspondingly, the amount of discounts given to these customers.)

[55] The SBF Energy Efficiency programs are administered by the Texas Department of Housing and Community Affairs. Information about the TDHCA weatherization assistance programs can be found at: http://www.tdhca.state.tx.us/assist_repair.htm

Additionally, TDUs and REPs are still in the process of resolving transaction discrepancies and auditing their records, resulting in amendments to their original remittances to the Comptroller and reimbursements requested from the fund. Also, requirements on the low-income discount administrator have been much higher than expected, resulting in larger expenditures on administration that originally estimated. This has resulted from customers relying heavily on the toll-free number for assistance in filling out the form, and more expenses related to determining a customer's eligibility than were originally anticipated.

2. LITE-UP Texas Program

Customers are eligible for the LITE-UP Texas program if their household income is at or below 125% of federal poverty guidelines, or they qualify for benefits from the Texas Department of Human Services (DHS). DHS clients are automatically enrolled. Other customers that qualify based on income can enroll via self-certification. The Commission has retained NCS Pearson as the low-income discount administrator (LIDA).

The Commission has actively worked with LIDA and REPs since January 1, 2002 to enroll eligible customers. Once a month, LIDA receives a client database from DHS, and files from ERCOT that identify the current REP for each customer in the state. LIDA matches these files, along with the customers who have mailed in self-certification forms, and posts a list of each REP's customers who are eligible for the discount on its website, accessible by secure password. REPs then access their respective list and apply the discount to their eligible customers' bills.

LIDA's responsibilities also include the processing of self-certification forms, answering customers' questions via the toll-free number, (866) 4-LITE-UP, and working the REPs and ERCOT to resolve enrollment discrepancies. Through the end of November 2002, LIDA processed over 100,680 self-certification forms. This process involves collecting the forms, entering the data, and putting the forms through the matching process. This year LIDA has addressed various problems including varying volumes of calls, improving quality, streamlining enrollment, and addressing issues related to customer move-ins and move-outs.

IV. EFFECTS OF COMPETITION ON RATES AND SERVICE

At this early stage, competitive forces appear to be working to bring many competitors to the retail market, encourage thousands of customers to choose a new provider, and reduce the electricity rates paid by consumers in Texas. In total, there are over 25 active REPs operating in the Texas market, and all classes of customers have a number of REPs offering service.

Since the ERCOT market transitioned to a single control area on July 31, 2001, daily wholesale power prices in ERCOT have remained reasonable, in both the bilateral and ancillary services markets. Temporary price spikes in August 2001 appear to be related to transmission congestion that occurred on these days, as well as market participants learning the new procedures of the ERCOT market after the transition to a single control area.

Retail customers in Texas are paying significantly less for electricity in 2002 as compared to the regulated rates in effect in 2001. Residential customers saved approximately $900 million in 2002 compared to regulated rates in 2001. Low-income residential customers have received an additional $68 million in discounts, or an average reduction of $136 per customer, through the end of October.

Residential customers have the opportunity to save even more by choosing another electric provider. As of December 2002, additional savings off the price to beat of up to 14% were available to residential customers.

Through August of 2002, commercial customers have saved, in total, approximately $420 million compared to rates in effect in 2001. Industrial customers appear to have saved at least $225 million compared to rates in effect in 2001.

Another way customers have been able to save money is by aggregating their energy load and negotiating with REPs as one buying unit. Eighteen different aggregation groups, including schools, and municipal and county electric customers, report estimated savings of approximately $123 million compared to the price to beat and over $134 million compared to rates the customers paid in 2001.

Customers in all customer classes have taken advantage of the opportunities available to them to switch providers. As of September 2002, over 400,000 retail customers were taking service from REPs not affiliated with their local transmission and distribution utility. Over 6% of residential customers were served by a non-affiliated REP, while 9% of small commercial, and over 16% of larger commercial and industrial customers receiving service from a non-affiliated REP in September 2002. For customers without a price to beat available from the affiliated REP, both the competitive REPs and the affiliated REPs can offer competitive rates. As of September 2002, over 85% of these customers have negotiated a competitive contract with either the affiliated REP, or another REP.

A. EFFECT OF COMPETITION ON PRICES

1. Wholesale Market Prices

Daily wholesale power prices in ERCOT have remained reasonable, in both the bilateral and ancillary services markets, since the ERCOT market transitioned to a single control area on July 31, 2001.

a. Bilateral Market Prices

The ERCOT market relies primarily on bilateral contracts between buyers and sellers of electricity as the principal mechanism by which power is traded. This is in contrast to other markets in the United States, where there is either a central power exchange or sizable day ahead and/or real-time markets that are administered by the independent system operator. A bilateral market gives REPs wide latitude to buy power for long and short terms and buy different packages to match the expected variances in its customers' demand for power over the next day, week, month, and year. This variety in contracting choices provides opportunities for buyers to insulate themselves and their customers from price volatility in the power market.

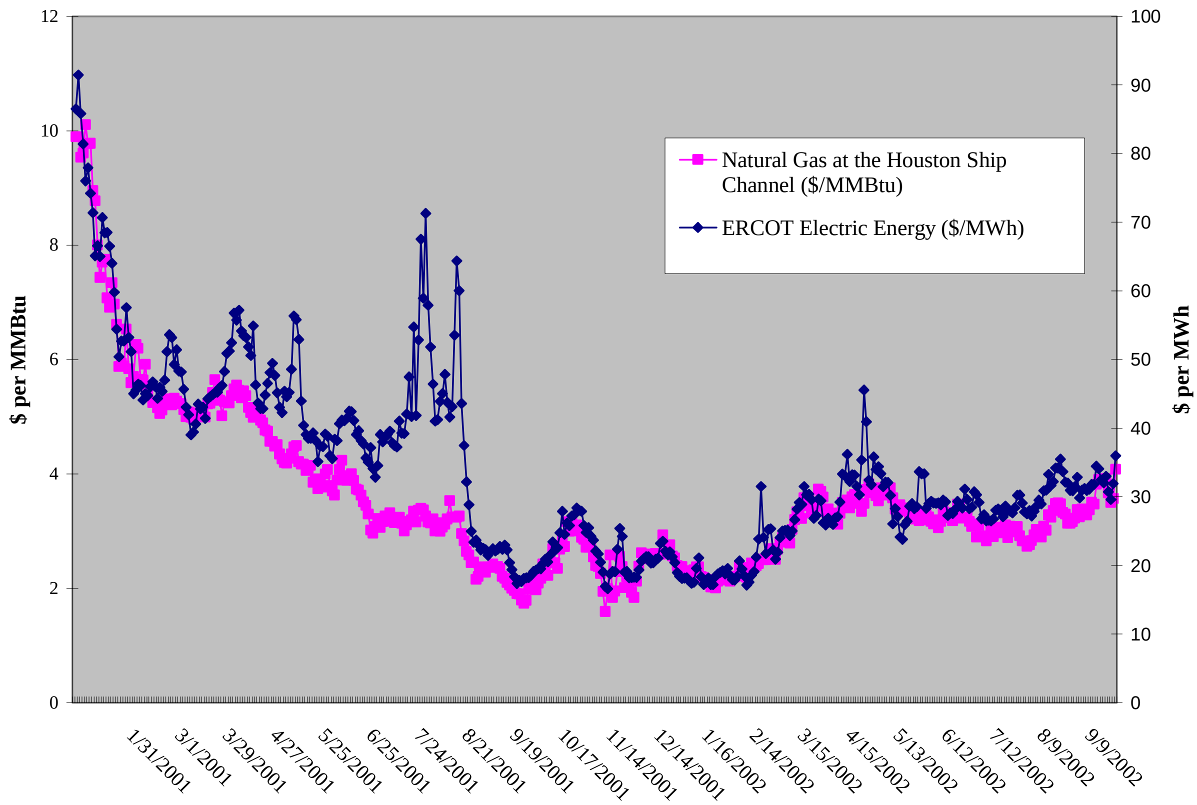
Two main concerns about a primarily bilateral market are price discovery and liquidity. Buyers and sellers generally negotiate in private, and currently do not have an obligation to disclose the price and terms of contracts to others. As such, it may be difficult for buyers and sellers to readily know the prevailing market price for a particular type of product. Liquidity is related to the volume of trades in a power market. Lack of liquidity makes it more difficult for a party that finds itself with too much or too little power to sell the excess or buy the deficiency in the market.

Private reporting firms have been able to report a significant amount of daily trades, and have also begun to segregate those prices by congestion zone and report forward prices. The following chart shows that, generally, daily power prices in ERCOT have remained reasonable and below $50 per MWh, except for brief periods of time in early 2001 and August 2001. The power market in ERCOT is very dependent upon natural gas prices, as natural gas fueled generation is the marginal (last) unit dispatched most of the year. In early 2001, natural gas prices rose significantly, and power prices followed. These prices declined significantly later in 2001.

Prices for several days in August 2001 also temporarily spiked. It appears that these price spikes were related to transmission congestion that occurred on these days, as well as market participants learning the new procedures of the ERCOT market after the transition to a single control area.

Prices in 2002 have been consistently below $40 per MWh, even in the summer months when demand is at the highest. This is due to the significant amount of new generation built in ERCOT over the last several years, along with lower than expected demand due to the nationwide economic slowdown, and cooler weather during the peak demand periods.

Figure 9: Comparison of Daily ERCOT Energy Prices and Natural Gas Prices



SOURCE: ERCOT's Daily Operations report.

Notwithstanding this data, lack of liquidity and price transparency appear to be ongoing concerns in the ERCOT market. Several market participants have expressed concerns that older and inefficient generation appears to be running at times when newer, more efficient generation is idle, raising a concern about the efficiency of the current market design. Also, a lack of price transparency may make it more difficult for retail customers, primarily larger commercial and industrial customers, to appropriately value offers for service. The Commission is currently exploring these issues in several pending rulemaking proceedings and projects.[56]

[56] *PUC Rulemaking on Oversight of Independent Organizations in the Competitive Electric Market*, Project No. 25959 (pending); *PUC Rulemaking Proceeding on Code of Conduct for Wholesale Market Participants*, Project No. 26201 (pending); *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376 (pending); and *Disclosure of Information Related to Electricity Transactions Originating or Terminating in Texas*, Project No. 26188 (pending).

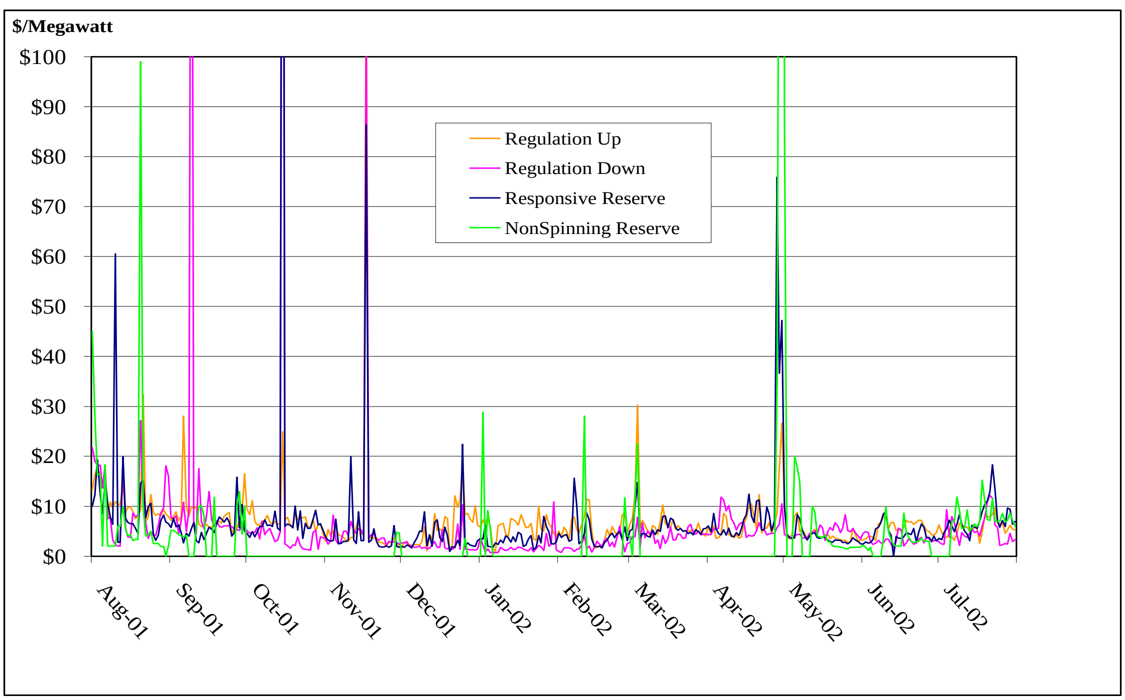
b. Ancillary Services Markets Prices

As the system operator, ERCOT must be able to deploy ancillary service capacity and balancing energy in order to maintain system reliability and resolve transmission congestion. For ancillary services, ERCOT assigns an obligation to each market participant based on its historical load. Market participants may acquire or provide the ancillary services themselves or rely on ERCOT to acquire the services through a centralized auction, conducted by ERCOT. The five ancillary services and the total amount required each day are shown below:

Regulation Up	1,200 MW
Regulation Down	1,800 MW
Responsive Reserves	2,300 MW
Non-Spinning Reserves	1,250 MW
Replacement Reserves	As Needed

During the first year of operation as a single control area, ERCOT usually procured from 10% to 20% of the ancillary service capacity required. It is apparent that market participants chose to provide their own ancillary services rather than expose themselves to unknown market clearing prices from the ERCOT auction. Nonetheless, prices for ancillary services procured by ERCOT were within a reasonable range. From August 2001 through July 2002, prices were below $20 per MW more than 95% of the time. The figure below shows the weighted average daily prices for the first four services. Replacement Reserves were not needed during the first year.

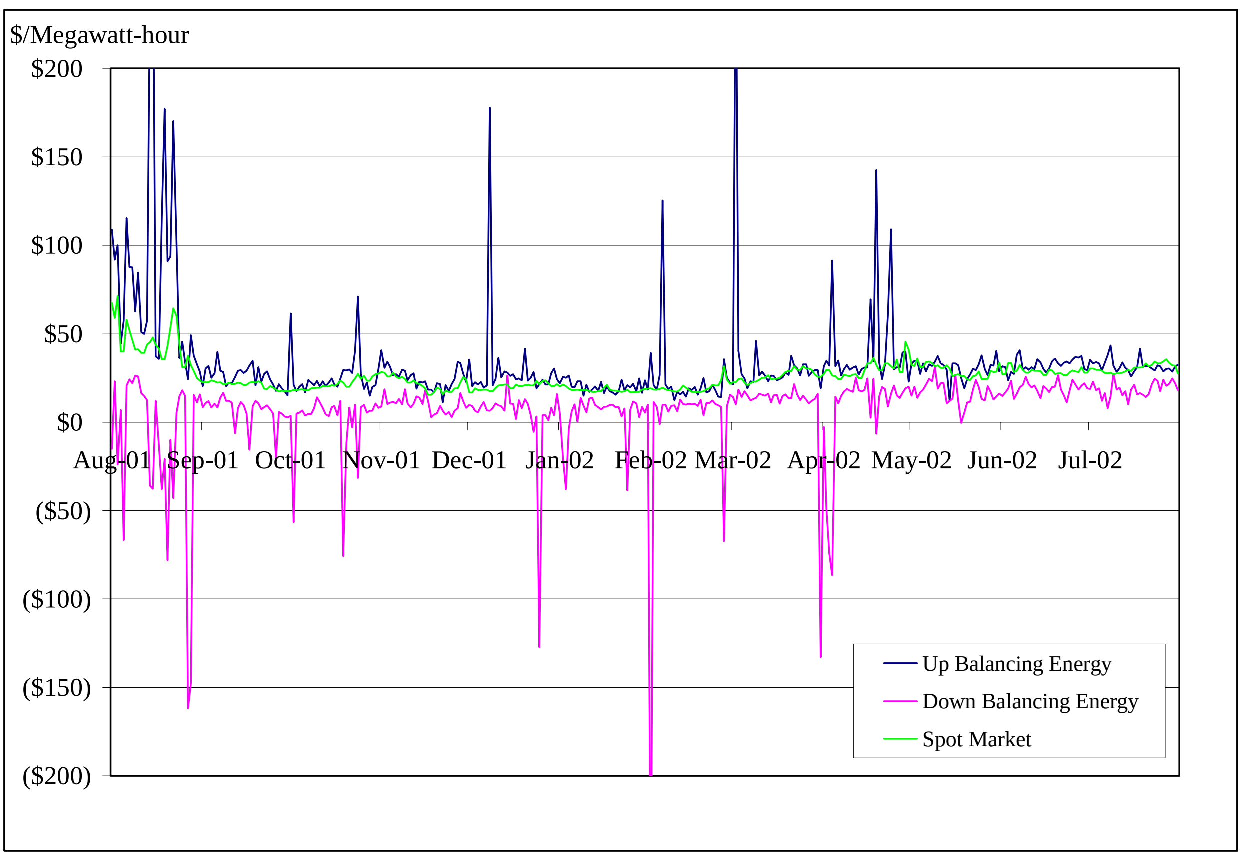
Figure 10: ERCOT Weighted Average Daily Price for Ancillary Service Capacity, August 2001 – July 2002



SOURCE: ERCOT's Daily Operations report.

Prices have also been generally reasonable in the ERCOT balancing energy market. ERCOT deploys balancing energy to maintain the balance between load and generation and to resolve transmission congestion. Nearly 277 million MWh of energy were consumed in ERCOT from August 2001 through July 2002, but less than 5% of total energy was transacted through the balancing energy market. The figure below shows the prices for Up Balancing Energy, and Down Balancing Energy, and it provides a comparison with energy prices in the ERCOT spot market, as reported in Megawatt Daily. Up Balancing Energy tends to be a slightly higher than the spot market, and Down Balancing Energy tends to be lower than the spot market. The price spikes shown could have occurred for many reasons such as a generator forgetting to place bids that resulted in a lean bid stack to misjudging weather conditions and not having the resources available. A negative price for Down Balancing Energy represents the amount that ERCOT will pay the generator to reduce its output while ERCOT takes on the additional responsibility, both operational and financial, to serve the load that was dedicated to the amount of reduced generation. The average daily price for balancing energy was within the plus or minus $50 per MWh range 90% of the time.

Figure 11: Weighted Average Price for Energy, August 2001 – July 2002



SOURCE: ERCOT's Daily Operations report.

c. Transmission Congestion and Balancing Energy Costs in August 2001

Significant transmission congestion occurred in ERCOT during August 2001, primarily caused by market participants scheduling power from the southern part of the state to the northern part of the state. This was not unexpected since much of the new, low-cost generation has been constructed in southern area of the state, and congestion typically occurs during the summer months when demand for electricity is the highest. However, the manner in which market participants (through their Qualified Scheduling Entities (QSEs)) scheduled their loads and resources became an issue. In accordance with the Protocols, ERCOT relieved the congestion by deploying balancing energy and aggregated the zonal congestion costs (as well as other costs related to load imbalance, resource imbalance, and uninstructed deviation) in a charge called the Balancing Energy Neutrality Adjustment (BENA). BENA charges were then allocated to market participants on the basis of their load. BENA charges for August alone were approximately $75.9 million.

As discussed in Section III.C, market participants had little incentive to schedule power in a manner that avoided creating transmission congestion because they would be allocated less in the way of BENA than they could receive as payments to relieve congestion. Additionally, if a market participant scheduled power for load that did not exist, they would receive payments from ERCOT (called "load imbalance payments"). Due to the high level of the BENA charges and this potential for gaming, concerns were raised by some market participants that BENA charges had been inflated by some market participants through intentionally overscheduling their loads. Other market participants argued that overscheduling was not intentional and was attributable to normal forecasting errors, new market rules, delayed switching, and other transitional problems in the new market.

The Commission staff investigated the scheduling behaviors of market participants and found that a number of QSEs had scheduled load with ERCOT that dramatically exceeded their actual load. While scheduling in this manner did not appear to have contributed to high power prices, it allowed these companies to increase their revenues in the ERCOT settlement process, at the expense of other market participants.

In particular, Commission staff found that six QSEs received more than $2 million each in load imbalance revenues for the month of August. Commission staff held several meetings and public workshops with the QSEs to assess the reasons for their overscheduling.

Ultimately, the Commission staff and five of the six QSEs entered into settlements that included an agreement that attributed overscheduling to market transition issues, including incomplete and inaccurate data in the marketplace and start-up errors. The settlement will result in refunds of approximately $10 million to other QSEs that had been assessed BENA charges caused by the overscheduling. The settlements were approved by the Commission in October 2002. Parties are still attempting to reach a settlement with the sixth QSE.

These overscheduling issues should not recur in the future because the change to direct assignment of zonal congestion costs removed incentives for QSEs to overschedule load. This change significantly reduced the total amount of congestion that occurs.

2. Retail Market Development and Prices

The relatively low wholesale prices in ERCOT have enabled REPs operating in Texas to effectively compete for customers.

a. Available Choices for Customers

One measure of competition is the number of alternate choices that are available to customers, even if they choose not to take advantage of those offers and instead choose to remain with the affiliated REP. In total, there are over 25 active REPs operating in the Texas market, and all classes of customers have a number of REPs offering service.

Residential customers in all service areas of the state have numerous offers available to them. As of December 2002, residential customers have between three and ten choices of REPs in their service areas, including the affiliated REP. Because some REPs are offering more than one product, customers have between three and eleven different products to choose from, including renewable energy in most areas.

The following table summarizes the number of REPs serving residential customers and the number of offers available to residential customers in each TDU area as of December 2002.

Table 10: Competitive Offers for Residential Customers in each Service Area

TDU	# of REPs*	# of all Products*	# of Renewable Products
Oncor	10	11	2
CenterPoint	10	11	2
CPL	7	8	2
TNMP	5	6	2
WTU	3	3	0

* Includes the affiliated REP providing price-to-beat service.
SOURCE: Competitive Residential Offers from the Texas Electric Choice website—
http://www.powertochoose.org/yourchoice/yourchoiceframe.html

Commercial and industrial customers appear to also have a large variety of offers from REPs. As of September 2002, there were approximately 19 REPs serving commercial and industrial customers in all service territories open to competition.

This market segment has developed differently from the residential market. Whereas the residential market operates primarily with publicly available, standard offers directed at mass-market solicitations of customers, the commercial and industrial market generally operates with individual contracts for the majority of these customers. Customers have been able to negotiate the type of service (firm vs. interruptible, short term vs. long term), and choose the amount of risk of price volatility (fixed price vs. indexed) they desire to accept. Customers who have negotiated contracts with the pricing tied to natural gas or power market prices enjoyed extremely low prices early in 2002 when natural gas prices (and power prices) dropped dramatically. Customers who have negotiated fixed price contracts have been able to avoid the subsequent increase in prices that have occurred this year, albeit at a price that reflects their REP absorbing that risk. Generally, however, all customers have enjoyed prices in 2002 that were significantly below the regulated rates they paid in 2001.

b. Residential Rates

As discussed in Section III.B, the price-to-beat rates adopted by the Commission effective January 1, 2002 provided savings to customers in the range of 8% to 18% compared to the rates in effect on December 31, 2001. While the adjustments to the price-to-beat fuel factors have reduced these savings, total rates remain below the level of December 2001, even with the increased fuel factors.

For residential customers, this has resulted in projected annual savings for 2002 of approximately $900 million compared to the rates in effect in 2001. Approximately $225 million of this reduction is related to the statutorily mandated 6% reduction in rates. $675 million of this reduction is attributable to reductions in fuel costs and the expiration of fuel surcharges. The annual savings by transmission and distribution utility (TDU) area are summarized below.

Table 11: Residential Price-to-Beat Savings for 2002

TDU	Residential Price-to-Beat Savings 2002
Oncor	$390 million
CenterPoint	$386 million
CPL	$68 million
TNMP	$44 million
WTU	$14 million
TOTAL	**$902 million**

SOURCE: PUC Electric Division.

The rates offered by non-affiliated REPs have varied throughout 2002 as REPs have altered their pricing in response to customer response, wholesale power costs, and the offers of other REPs. The savings available under various offers have correspondingly changed throughout the year. The Commission maintains a monthly residential pricing comparison analysis for each area of the state open to competition.

It is difficult to estimate the additional savings that customers have achieved by switching to a competitive REP because of the myriad of pricing offers that have been available this year. However, preliminary estimates made by the Commission suggest that residential customers who did select another REP on the basis of price have already saved, at a minimum, an additional $11 million through December of 2002 off the price to beat.[57]

As of December 2002, additional savings off the price to beat of up to 14% were available to residential customers. A household using an average of 1,000 kWh per month can save as much as $166 a year by switching to the lowest competitive offer in some areas. Customers who signed up on long-term contracts earlier in the year at rate levels that are no longer available may see savings in excess of this amount. The following chart summarizes the additional annual savings that would be realized by residential customers in Texas if they switched to the lowest current offer available in their area.

Table 12: Additional Annual Residential Savings Available from Lowest Competitive Offer

% Switched	Additional Annual Savings Available
5%	$32 million
10%	$64 million
15%	$95 million
20%	$127 million
25%	$159 million
100%	**$636 million**

SOURCE: PUC Electric Division and Competitive Residential Offers from the Texas Electric Choice website—http://www.powertochoose.org/yourchoice/yourchoiceframe.html

Customers have also demonstrated a significant amount of interest in renewable rate offerings. These offers have typically been priced at a premium to the price to beat, but provide customers an option of choosing power produced by 100% renewable resources.

c. Commercial and Industrial Rates

Savings for commercial and industrial customers are more difficult to estimate than residential customers because of the greater differences in how these customers use power and the prices they pay. Small commercial customers eligible for the price to beat have generally received rate reductions in the same range as residential customers of 8% to 18% if they stayed

[57] This estimate was developed by multiplying, for each month of January 2002 to September 2002, the difference between the then-current average price to beat and the then-current average rate offered by each non-affiliated REP in a particular TDU area by the MWhs sold by that REP in that area, as provided by the TDU. Estimates were made for October 2002 through December 2002 by multiplying the difference between the then-current average price to beat and then-current average rate of each REP by a forecast of the MWhs sold by that REP, assuming a linear growth in the REP's market share. This calculation tends to underestimate the additional savings achieved by residential customers because it assumes each customer is on the current publicly available offer of the REP in the respective month. In reality, many customers sign fixed price, term contracts and do not have their rates change every month. Customers that signed those contracts earlier in the year, when prices were lowest, will in reality see additional savings over the price to beat than reflected here. Also, MWh sales reported by the TDUs may be understated due to the switching problems and other data issues discussed elsewhere in this report. Data submitted by REPs to the Department of Energy's Energy Information Administration suggest that the MWhs sold by REPs could be larger than that used in this estimate

with the affiliated REP. Large commercial and industrial customers do not have a price to beat, and therefore savings for these customers are even more difficult to estimate.

The Commission has been able to derive estimates of savings from data that many REPs are required to report to the Department of Energy's Energy Information Administration (EIA). Through August of 2002, this data suggests that commercial customers have saved, in total, approximately $420 million compared to rates in effect in 2001. Industrial customers appear to have saved at least $225 million compared to rates in effect in 2001.[58] Actual savings are likely in excess of these estimates, as some REPs appear to have not reported data to the EIA. For example, in discussions that Commission staff has had with REPs, one large REP serving commercial and industrial customers has calculated savings to its customers in excess of $500 million compared to the rates in effect in 2001.

d. Aggregation Projects

One of the ways customers have been able to save money is through aggregation programs whereby they pool their purchasing power and negotiate with REPs as one buying unit. Eighteen aggregation groups were able to quantify the energy cost savings achieved for their customers, predominately commercial and industrial customers, and political subdivisions, such as school districts and municipal and other local government customers. They report estimated savings of approximately $123 million compared to the price to beat and over $134 million compared to rates the customers paid in 2001.[59]

The following table summarizes the savings achieved by the 18 aggregation groups that reported to the Commission.

Table 13: Aggregation Savings

Type of Customers	Savings Over the PTB	%	Savings Over 2001 Rates	%
Commercial and Industrial	$8 million	14%	$15 million	25%
Political Subdivisions	$115 million	26%	$119 million	32%
Total	**$123 million**		**$134 million**	

SOURCE: Data filed in Project No. 26280.

[58] The reports each REP is required to file with the EIA include, for each month of the year, MWh sales, revenue, and number of customers by customer class. During 2001, each of the integrated utilities was required to file similar data. From this data, it is possible to derive an average price per kWh each REP is charging commercial and industrial customers and compare it to the average price per kWh that customers paid in 2001. Savings for these classes of customers can then be derived from these average prices.

[59] Reports were submitted to the Commission by September 1, 2002, and cover the reporting period of July 1, 2001 through June 30, 2002. The reporting entities' methodology for quantifying cost savings vary and have not been subject to verification by the Commission.

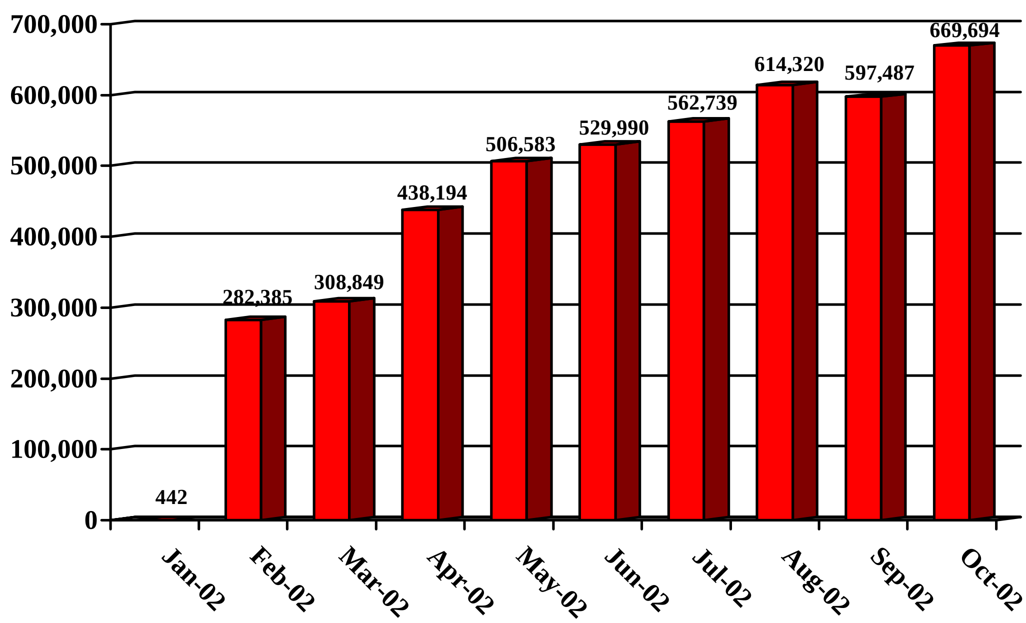
3. System Benefit Fund Low Income Rate Discount Program

The Commission has worked actively with the Texas Department of Human Services (DHS) and the low-income discount administrator (LIDA) since January 2002 to enroll eligible customers in the low-income discount program through a combination of automatic enrollments and customer self-certification. Additionally, the Commission is engaged in an ongoing campaign to enroll additional eligible customers in the program through outreach, which includes:

- Requiring REPs to send a mail insert describing the program twice a year, and to mail self-certification forms to requesting customers;
- Distributing a brochure and a fact sheet informing customers of available low-income programs through DHS, local community agencies, and TDHCA;
- Mass mailing the application forms to those customers who could not be automatically enrolled. By the end of April 2002, 206,000 applications were mailed. LIDA has been processing the returned applications, which have totaled 31,708 through the end of July 2002. This total represents a 15.4% response rate, well within the accepted range for mailings of this type.

These efforts have resulted in an increase in the number of customers receiving the discount from 442 in January 2002 to 669,694 in October 2002.

Figure 12: Number of Customers Enrolled in Low-Income Discount Program

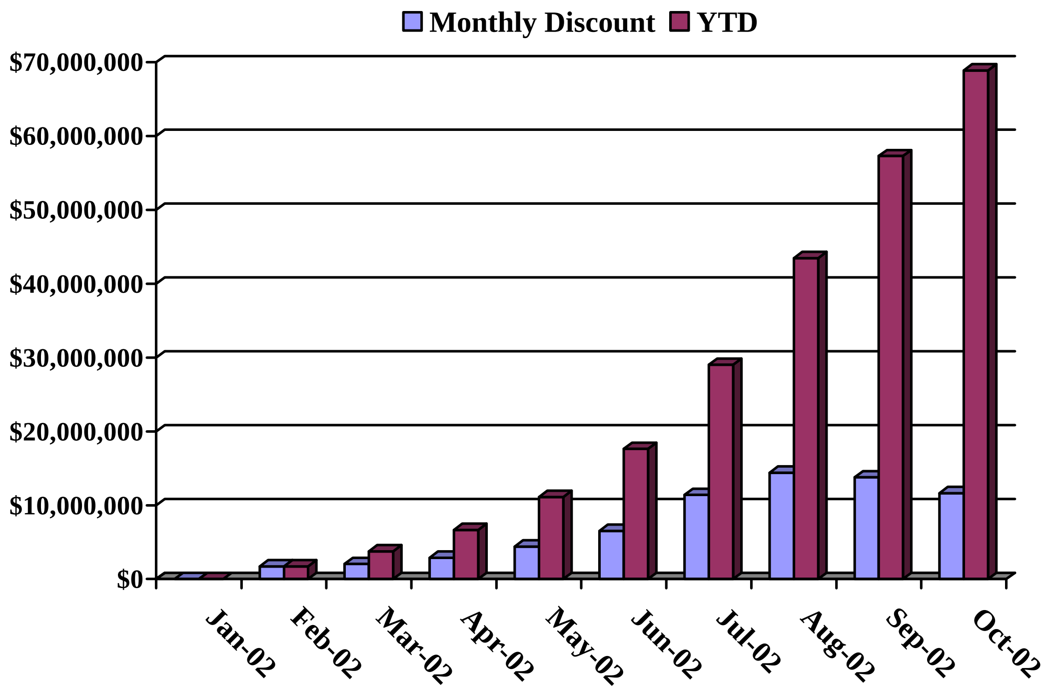


SOURCE: Monthly REP reports filed in accordance with P.U.C. SUBST. R. 25.451.

As of October 2002, the average customer enrolled in the program had received monthly discounts in the range of $6.00 to $23.00 per month and a total of $136 in discounts since January 2002. Discounts for the summer months are higher due to higher usage in these months, as well as an increase in the amount of the discount by the Commission in June 2002 from 10% to 17%.

As of October 2002, low-income customers statewide have received a total of $68 million in electric rate discounts since January 2002. The following chart shows the total amount of discounts for each month of 2002 through October and the year-to-date total as of the end of October 2002.

Figure 13: Total Monthly and YTD Discounts Given to Customers through October 2002

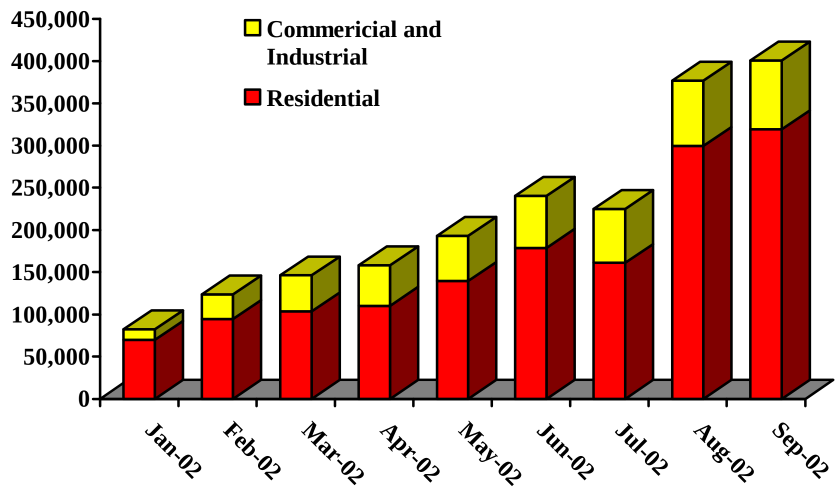


SOURCE: Monthly REP reports filed in accordance with P.U.C. SUBST. R. 25.451.

B. CUSTOMER SWITCHING

As of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area.[60] This number represents approximately 6.8% of all customers in areas open to customer choice.

Figure 14: Number of Customers Served by a Competitive REP in ERCOT



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

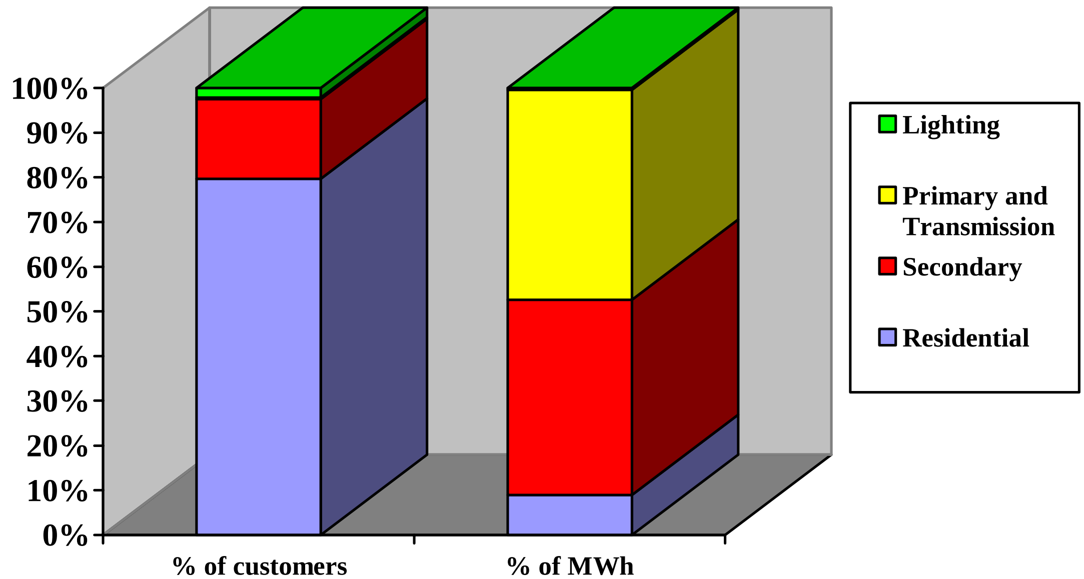
Of these premises, 319,297 (80%) are residential customers. Approximately 18% (71,691 customers) of the customers are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price to beat). There are 1,322 (less than 1%) larger commercial and industrial customers taking service at the primary and transmission voltage level. The remaining premises are lighting accounts.

A total of 6,070,477 megawatt hours (MWhs) were served by non-affiliated REPs in September 2002.[61] This represents approximately 25% of the total MWhs sold in September. This number is higher than the percentage of customers who have switched because the larger commercial and industrial customers comprise a significant portion of the energy consumption in the state. While commercial and industrial customers only account for 20% of the customers who have switched, these customers comprise over 90% of the megawatt hours (MWh) served by non-affiliated REPs in areas open to competition.

[60] This includes approximately 73,000 customers (mostly residential) that were being served by a POLR in September 2002.

[61] This includes approximately 100,000 MWh that were being served by a POLR in September 2002.

Figure 15: Class Composition of Customers and Megawatt-hours Served by a Competitive REP as of Sept. 2002



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

1. Residential Market Switching

Residential customers comprise the majority of the customers who were served by non-affiliated REPs as of September 2002, with 6.0% (319,297 customers) of all residential customers in areas open to competition receiving service from a non-affiliated REP in their area.[62] REPs serving the residential market face several challenges to acquiring retail customers, including:

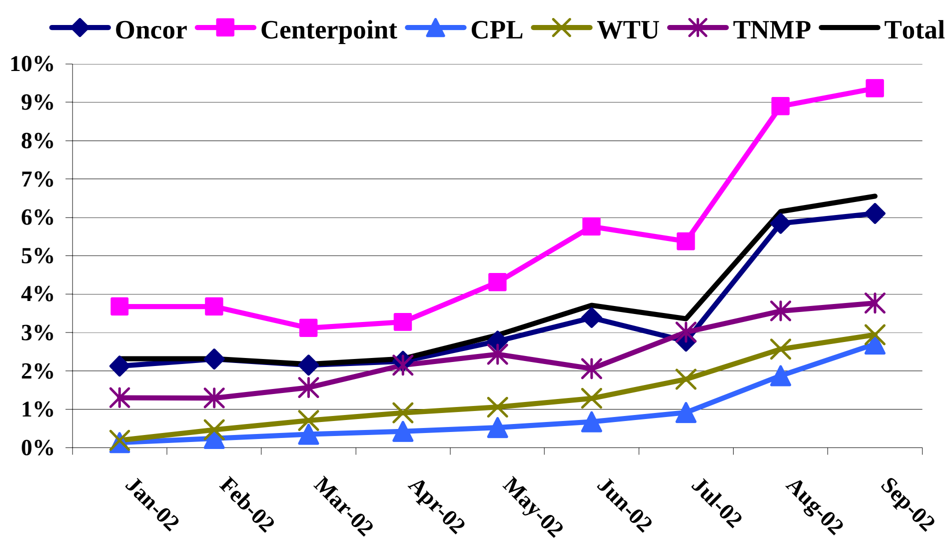
- Increased customer protections for residential customers (*i.e.*, implementation of the low-income discount and requirements related to issuing terms of service documents and Your Rights as a Customer documents) that makes it more costly to serve these customers;
- Substantial customer acquisition costs (*i.e.*, advertising, direct-mail solicitations, incentives to entice customers to switch);
- Increased costs relating to investments in billing systems, call centers, and customer complaint resolution resulting from the need to serve a large volume of customers; and
- Negative perceptions of the electric industry resulting from the California energy crisis, Enron bankruptcy, and accounting and financial scandals involving energy companies, including Texas companies.

[62] As of September 2002, 69,424 residential customers (about 0.8%) were served by the POLR. These customers are included in the switching analysis even though many of these customers were transferred to the POLR by the affiliated REP, and as such, may overstate the number of customers actively choosing another REP. However, other factors, such as customers who have switched back to the affiliated REP after initially switching to another provider, may understate the number of customers who have actively chosen another REP at some point in time.

REPs appear to have initially focused their efforts in the large urban markets of Houston and the Dallas-Ft.Worth Metroplex due to the scale achieved in marketing efforts in this area. Over the course of 2002, REPs have continued to focus their efforts in these areas, but have also begun to expand into south and west Texas. It is perhaps not surprising that the more non-affiliated REPs that are active in a particular service area, the more customers have switched.

Customer response to the offers of non-affiliated REP has been the strongest in the CenterPoint service area (Houston, formerly Reliant Energy HL&P) with over 9.0% of residential customers (145,625 customers) receiving service from nine different non-affiliated REPs as of September 2002.[63] Oncor's (TXU) service area was second, with slightly over 6.0% of residential customers (146,814 customers) receiving service from non-affiliated REPs.[64] This is most likely a response to the intensive marketing activities in these areas (TV, radio, print ads, and door-to-door marketing). The other service areas (TNMP, CPL, and WTU) have lagged behind the CenterPoint and Oncor area, but have seen increased switching in August and September.[65]

Figure 16: Percentage of Residential Customers Served by a Competitive REP



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

---

[63] As of September 2002, 1.6% of residential customers were served by the POLR in the Centerpoint area.

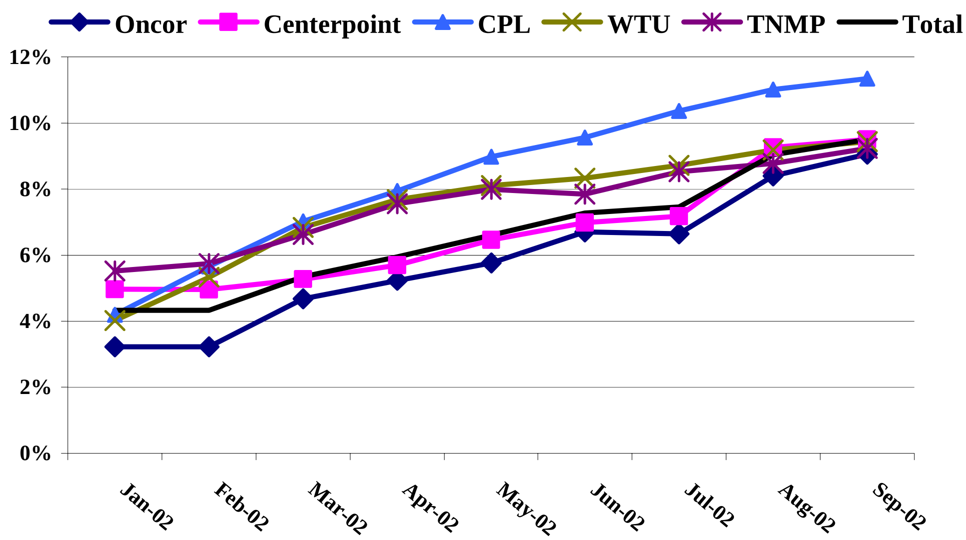
[64] As of September 2002, 0.9% of residential customers were served by the POLR in the Oncor area.

[65] As of September 2002, 3.8% of residential customers (6,644 customers) in the TNMP area were served by a non-affiliated REP; 2.7% of residential customers (15,878 customers) in the CPL area were served by a non-affiliated REP; and 2.94% of residential customers (4,336 customers) in the WTU area were served by a non-affiliated REP.

2. Secondary Voltage Level Commercial and Industrial Market Switching

Commercial and industrial customers taking service at the secondary voltage level (primarily smaller commercial and industrial customers, most of which are eligible for the price to beat) have shown a greater propensity to switch to a non-affiliated REP, in part due to the fact that the energy consumption of these customers is much higher than residential customers, and as a result, the absolute level of savings is more significant on a per-customer basis. As of the end of September 2002, over 9% of these customers (71,691 customers) were receiving service from a REP not affiliated with the TDU in their area. Customer response for this set of customers has been highest in the CPL area (10,874 customers, or nearly 11% of the customers) and the WTU area (3,800 customers, or about 9% of the customers). Other areas show approximately 9% switch rates. Geographic distinctions are less important for these customers because of the individual contract negotiation in this segment of the market.

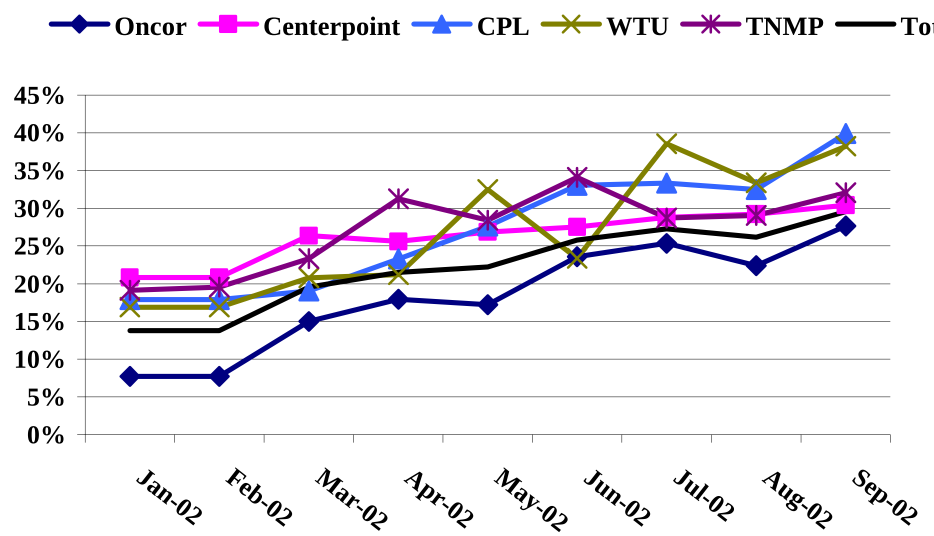
Figure 17: Percentage of Small Commercial Customers Served by a Competitive REP



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

Although less than 10% of all secondary voltage customers (68,133 customers) have switched, the ones who have switched are among the largest customers in these customer classes, as evidenced by the fact that about 25% of the MWh (about 1.8 million MWh) used by secondary voltage level customers were supplied by non-affiliated REPs. The CPL and WTU service areas show non-affiliated REPs making the greatest in-roads, as almost 40% of the MWhs (about 303,000 MWh) of this set of customers in these areas were served by REPs other than the affiliated REP in September 2002. Other service areas showed similar results, with at least 28% of the MWh in each area served by non-affiliated REPs. These results illustrate that the large customers who use a significant amount of electricity are more likely to fully explore their options in the marketplace for alternatives to price-to-beat service from the affiliated REP.

Figure 18: Percentage of Secondary Voltage MWH Served by a Competitive REP

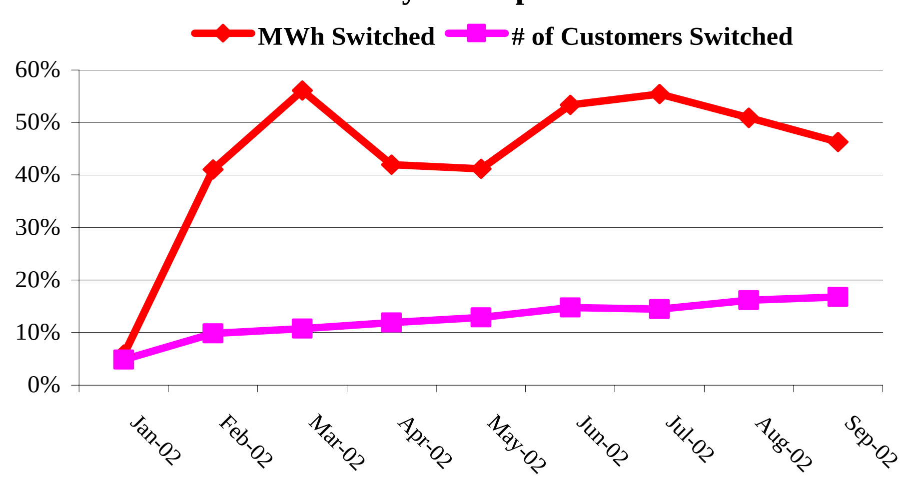


SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

3. Primary and Transmission Level Voltage Commercial and Industrial Market Switching

Commercial and industrial customers taking service at primary or transmission voltage levels show a similar trend. These customers are generally larger commercial and industrial customers, many of which are not-eligible for the price to beat. Over 16% of these customers (1,272 customers) and approximately 50% of the MWhs (1.7 million MWh) used by these customers were served by REPs not affiliated with the TDU in the customer's area. This analysis is not broken out by TDU area out of concerns related to the confidentiality of market share information for these customers by the affiliated REPs. However, the trends are the same across TDU areas with respect to the number of customers that are being served by non-affiliated REPs.

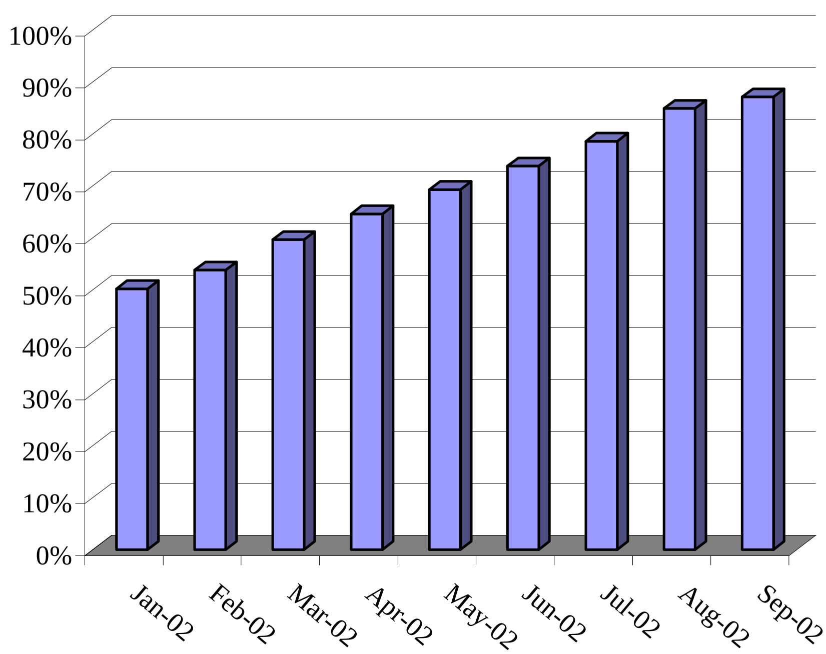
Figure 19: Percentage of All Primary and Transmission Voltage Customers & MWh Served by a Competitive REP



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

For customers without a price to beat available from the affiliated REP, simply looking at the percentage of customers or MWh served by non-affiliated REPs does not present the full picture of competition for this segment. The Commission required affiliated REPs to notify non-price-to-beat customers of the rate they would be charged on January 1, 2002 if they did not negotiate other arrangements with the affiliated REP or switch to another REP. As of September 2002, slightly more than 10% of non-price-to-beat customers (340 customers) remained on this default pricing offer, meaning that approximately 85% of these customers (2,296 customers) have actively negotiated a competitive contract with either the affiliated REP or another REP. Because this set of customers are very large customers, with, in many cases, tremendous amounts of energy use, there was a clear economic incentive for these customers to fully explore their options in the competitive market. Additionally, the default offers of the affiliated REP were generally either a very high fixed price offer, or a pass-through of market prices, imparting tremendous risk to the retail customer. These pricing offers provided an added incentive for customers to shop for the best available price, as in many cases, the default offers could have lead to rates higher than those in effect in 2001.

Figure 20: Percentage of Non-Price-to-beat Customers with a Competitive Contract



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from Affiliated REPs.

4. Service by the Provider of Last Resort

As discussed in Section III.A, the POLR was initially designed to serve two sets of customers: (1) customers transferred to the POLR due to non-payment or other contract breach with their REP, and (2) customers of a REP that had decided to leave the market and did not make other arrangements to transfer the customers to another REP. All customers on POLR service as of September 24, 2002 fell into the first category.

The following table summarizes the number of residential customers served by the POLR for each month of the year through September 2002 compared to the number of disconnections for non-payment of electric bills that occurred from January 2001 through September 2001 by the integrated utilities. As of September 24, 2002, REPs could no longer transfer non-paying customers to the POLR, and instead began transferring them to the affiliated REP, which will have authority to disconnect the customers if the customer does not establish any required deposit with the affiliated REP, or subsequently does not pay a bill of the affiliated REP.

Table 14: Comparison of 2002 Transfers to POLR vs. 2001 Disconnects

TDU	Transfers to POLR through Sept. 27, 2002	Disconnects through Sept 2001
Oncor	36,575	93,084
CenterPoint	43,742	112,456
CPL	11,438	44,937
TNMP	2,104	29,691
WTU	1,220	12,103
TOTAL	**95,079**	**292,271**

SOURCE: ERCOT Daily Transaction Reports and Data from Investor Owned Utilities.

C. RETAIL MARKET TECHNICAL ISSUES

1. Switching Issues

As discussed in Section III.G, the pilot programs revealed many deficiencies with the systems used to switch retail customers to the REP of their choice. While progress has been made to correct these deficiencies, the problems have continued into full retail competition and some continue to affect the market and customers today.

On December 17, 2001, ERCOT began accepting switch requests for service commencing on the date of the customer's regularly scheduled meter read in January 2002. Many switches that were submitted to be effective in January were not processed in accordance with the ERCOT Protocols. As a result, those customers were automatically transferred to the affiliated REPs in January. Residential and small commercial customers (with a peak demand of 1 MW or less) awaiting switches after their January meter read were charged in accordance with the affiliated REPs' price-to-beat tariffs. Large commercial and industrial customers awaiting switches were charged the unregulated default rates of the affiliated REP. In many cases, the difference between the default rate of the affiliated REP and the price that a customer had negotiated with another REP was substantial.

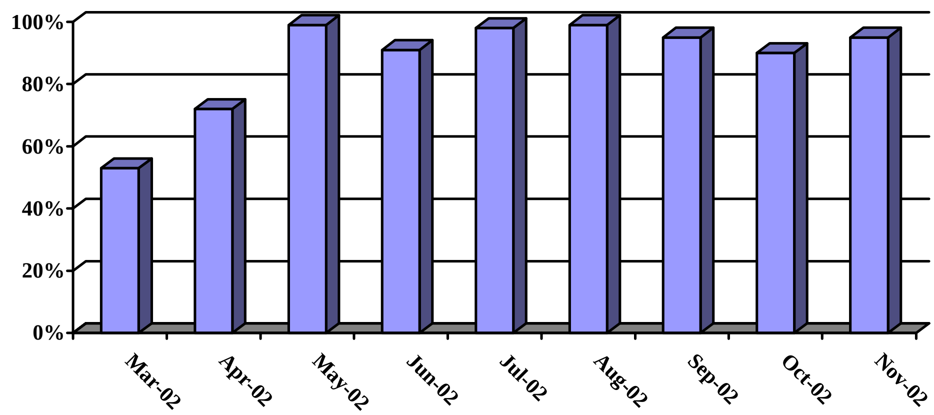
ERCOT's Retail Market Subcommittee (RMS) formed a task force to address wholesale and retail settlement issues caused by errors and/or delays in the processing of switch requests for non-price-to-beat-customers submitted from December 17, 2001 through January 19, 2002. RMS, and ultimately the ERCOT Board of Directors, determined that it was appropriate to "back-date" the switches of these customers such that a customer would be billed as if the switch had been completed within the appropriate timeframe. As of November 2002, the backdating for all eligible customers had been completed.

Problems with missing, late, and out-of-sequence transactions continue to persist in the market. Switching a customer from one REP to another is a multi-stage process involving electronic communications between the new REP, the customer's TDU, and ERCOT. No single problem has been as the cause of missing and late switch transactions. Rather, multiple issues affecting various transactions have and continue to be identified and resolved. Problems that have contributed to missing or late transactions include information system outages or malfunctions, viruses, and simple data quality issues. Missing and late transactions have and continue to be resubmitted by market participants as necessary.

Market participants and the Commission expended considerable effort and resources to resolve these problems through manual workarounds, system upgrades, and extensive reconciliation and tracking efforts. ERCOT also established a Quick Recovery Effort (QRE) process as a way to expedite resolution of switching delays and to identify common problems that are experienced by multiple market participants. ERCOT and the Commission also worked with stakeholders through RMS and developed detailed data samples (Market Metrics) from REPs, TDUs, and ERCOT as a way to facilitate discovery of common systems problems, and to isolate where in the transactions process failures were occurring. As a result, success in switching customers has improved dramatically since the beginning of the year. The Commission is currently working with ERCOT to migrate from the current method of utilizing data samples to analyze systems performance to measuring the entire universe of transactions through the entire switch process in order to better isolate deficiencies in market participants' and ERCOT's systems.

The following chart shows the trend in switching success over the course of the past year. This analysis has been prepared from sample data submitted as part of the Market Metrics process, and may not represent the experience of specific REPs in the market. However, the Commission believes it is an adequate representation as to the state of the market systems.

Figure 21: Percentage of Switches Completed Successfully, March - November 2002



SOURCE: Data Responses filed in Project No. 24462.

2. Move-Ins/Move-Outs

Under regulation, when customers moved into a new residence, they contacted the local utility to initiate service at the new residence. Traditionally, the tariffs of the integrated utilities have required the utility to establish service within seven days of the request. However, in practice, service was usually established in a much shorter time period of one or two days. In the restructured electric market, a customer must contact a REP for service, with the REP subsequently contacting the local TDU to begin service. Ideally, this process should take the same time period as it did prior to regulation, or at most, a day longer for the REP to forward the request to the TDU.

In the case of a new home or business, the builder or developer must first notify the local wires company that a new address has been established. The local wires company must assign the new address an electronic service identifier (ESI ID) in ERCOT's database before the customer can choose a REP and turn on electric service. This process may add several additional days to the move-in process.

The new move-in process was one of the transaction series that was not tested during the pilot program because only current customers of the utility could participate and choose to switch to a REP. During January, numerous customers reported extreme situations in which they waited more than a week to receive service at a new residence. None of those cases involved simple moves from one premise to another, as is the case with the vast majority of move-ins. The complicating factors included new meter and/or transformer installation, required city inspections, newly constructed premises, and combinations of any or all of these.

After the retail market opened, there was some confusion among REPs and TDUs relating to computer systems used to process new service requests, resulting in considerable delays. ERCOT reported in early January 2002 that five specific problem areas were identified regarding the move-in/move-out process:

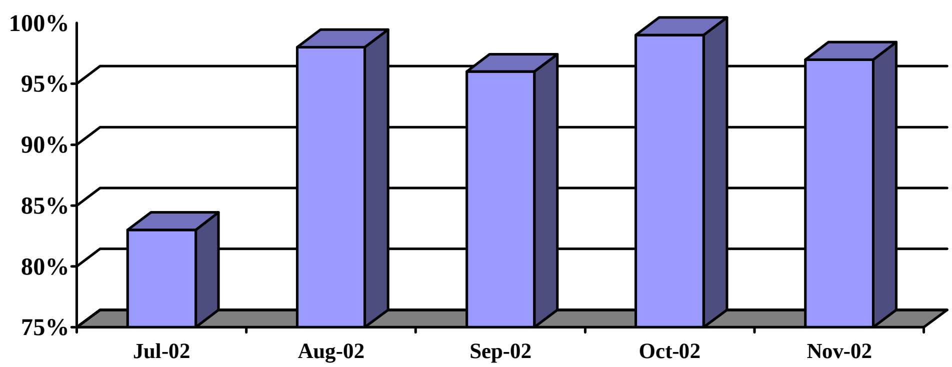
- Customers needed to choose a REP at a new service address instead of simply switching an existing customer at an existing service address;
- REPs had problems generating a proper request to initiate service;
- REPs had problems matching electric service identifiers (ESI-IDs) with apartment or street addresses;
- Errors in processing transactions within the ERCOT system, and;
- TDUs had problems transmitting acknowledgements back to ERCOT.

In response to these difficulties, TDUs agreed to stop disconnecting residential customers who moved out of premises in order to ensure that a subsequent customer moving in would not have an unreasonable delay in establishing service. Additionally, a manual work-around process was developed whereby REPs send (via fax or e-mail) daily "safety net" lists in order to ensure that customers scheduled to move-in the following day are on the TDU's service list.

As a result of these processes, retail customers are receiving service in a much more timely fashion than they were at the beginning of the year, in many cases via the safety net process. ERCOT currently has a task force working to address the systemic systems issues related to move-ins and move-outs, and significant system changes are expected to be needed. Nevertheless, the vast majority of customers are being moved-in on the same day as requested or the next day, even though the electronic transactions may not flow within protocols.

The following trend chart illustrates the improvement in performance that has occurred since July of this year, when the Commission began receiving data related to move-in requests.

Figure 22: Percentage of Move-Ins Completed Successfully, March-November 2002



SOURCE: Data Responses filed in Project No. 24462.

3. Metering and Billing Issues

REPs have also experienced difficulty in billing retail customers during the early months of retail competition.

Each month the local TDU electronically sends customers' electric usage information to ERCOT. ERCOT electronically forwards the meter read immediately to the REP. Subsequently, ERCOT processes the meter read data for settlement purposes. The REP reconciles the meter read from ERCOT with the invoice sent directly from the TDU for non-bypassable charges and prepares the customer's bill.

REPs continue to experience significant problems in receiving timely usage information from ERCOT and the TDUs and in the performance of the necessary reconciliations. Some REPs are able to generate an estimated bill from only the meter read or TDU invoice while others require both the meter read and the TDU invoice before a customer bill can be prepared.

The metering and billing information transactions chronologically follow the switching transactions described above. Therefore, many of the metering and billing transactions were also affected by the problems with the switch transactions. In addition, improper transaction sequences are a factor in missing and late transactions. Because the market participants' systems require transactions to arrive in a particular sequence, those that arrive out of sequence are often rejected. Even if such transactions were not rejected, the information contained in them is often of little use without the missing or late prerequisite transactions.

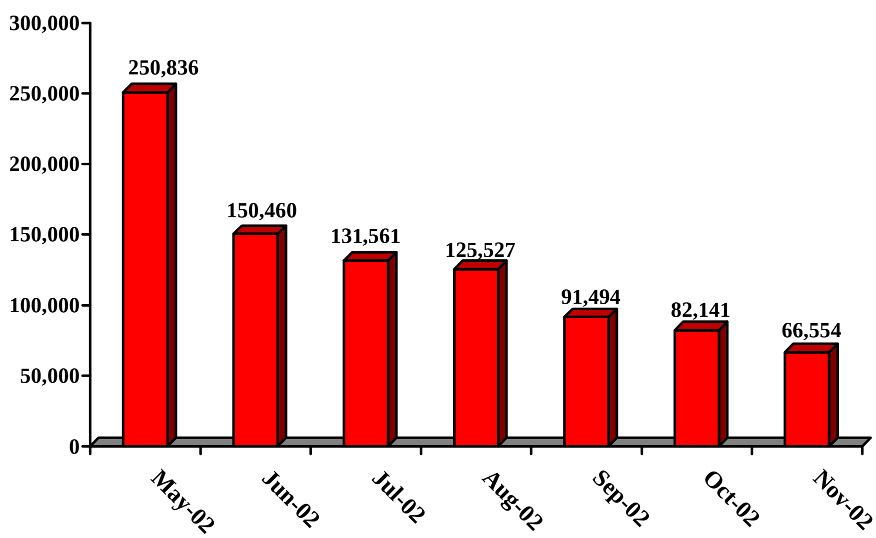
In some instances, the metering information transactions did not complete the path from TDU to ERCOT to REP. Many of the problems were found to be in the forwarding mechanism of the ERCOT registration system. In November 2001, ERCOT made changes to both hardware and software to improve the routing of these transactions. Also at a November 29, 2001 workshop, the Retail Market Subcommittee developed a contingency plan in which TDUs would send these transactions directly to REPs in the event ERCOT was unable to forward the required volume.

Another major problem that has been experienced by REPs is difficulty in reconciling the metering information transactions with the invoice for TDU charges that is received directly from the TDU. Discrepancies have been identified in both the cross-reference information designed to allow matching between these transaction types, as well as the metering information contained in each. Some of the cross-reference errors were caused by the necessity to re-send transactions to be processed properly in the systems. Duplication caused by these re-sent transactions was also an issue.

The ability of REPs to manage customer accounts affected by one or more of these errors varies by REPs, usually in proportion to the number of customers served. REPs with a small number of customers are often able to bill their customers' accounts through manual intervention (e.g., estimated bills), while volume constraints prevent REPs with large numbers of customers from doing so. At least one REP has reported that they cannot bill some customers until the problems with the delivery of the metering information transactions are resolved.

The issues affect retail customers when the customer's REP is unable to issue a bill (or bills) to the customer for several months. Initially, a large number of retail customers were receiving no bill, or bills for multiple months as REPs caught up. Commission rules require REPs billing for multiple months of charges give customers as many months to pay as months of charges that are billed (*i.e.*, if a bill includes three months of charges, the customer has three months to pay the bill in its entirety). Billing performance has improved dramatically in recent months, and most customers are receiving bills on a timely basis. Several REPs have continued to lag in issuing timely bills, and the Commission is actively working with these companies to improve their performance.

Figure 23: Number of Customers Missing One or More Bills, May-November 2002



SOURCE: Data Responses filed in Project No. 24462.

Prior to retail competition, integrated utilities were often unable to issue monthly bills to some customers due to meter reading issues, billing systems issues, delays associated with quality assurance, or other reasons. Traditionally, 1.0% to 5.0% of customers did not receive a timely bill each month due to these reasons; but in the majority of cases, bills were not delayed for more than a month. Current billing rates are within the historical range of timeliness (and in fact near the low end), and 60% of current delinquent bills are less than 60 days delayed. However, 23% of the remaining delayed bills have been delayed for more than 90 days. These bills represent the greatest concern with respect to the impact on retail customers, and the Commission is actively working with REPs to reduce this backlog.

V. ASSESSMENT OF OTHER SENATE BILL 7 GOALS AND BENEFITS

A. RENEWABLE ENERGY GOAL

The construction of renewable energy facilities has proceeded significantly quicker than the mandates in PURA § 39.904, *Goal for Renewable Energy*. The mandate required that 400 MW of new renewable capacity be installed in Texas by 2003. As of October 1, 2002, approximately 1,000 MW had been installed. The Commission believes that the full mandate of 2,000 MW, required to be installed by 2009, may actually be met as early as January 1, 2004.

The vast majority of installed renewable capacity is wind generation, with limited amounts of landfill gas, small hydroelectric, and solar generation. Uncertainty regarding the expiration of the federal production tax credit (PTC) caused a rush to install wind capacity in 2001 (almost 1,000 MW during that year alone), and the Commission anticipates another rush of development in 2003 due to a reprise of the same uncertainty. The PTC, currently $18 per MWh, will expire at the end of 2003 unless it is extended by Congress and the President.

The rush to install new wind farm capacity was strongest in the McCamey area of West Texas (Crane, Pecos, Upton, and Crockett counties), where 758 MW of new wind power has been installed and another 300 MW is expected to be in service by the end of 2003. However, the local transmission network currently can only export 400 MW. This has resulted in routine wind power curtailments, higher transmission congestion costs, and some damage to transmission equipment due to overloading. The transmission utilities serving the McCamey area are seeking approval for upgrades that would increase export capacity to 2,000 MW, but these improvements would not be finished until 2007 or later.

The Commission is concerned that transmission constraints could limit the delivery of renewable power to customers, especially if the capacity mandate were achieved by 2004. The transmission problems that have arisen in the McCamey area could arise elsewhere, depending on where future wind generation is sited. The Commission has opened Project No. 25819, *PUC Proceeding to Address Transmission Constraints Affecting West Texas Wind Power Generators*, to find ways of addressing this problem under existing statutory authority.

Additionally, the lack of proper wholesale price signals may have exacerbated the transmission constraints in the McCamey area. Had the wind generators been required to pay for transmission congestion they caused, new generators would have had an incentive to avoid the McCamey area and locate instead where transmission was sufficient (assuming other sites are as amenable to the location of wind generation). The Commission is addressing locational pricing issues in Project No. 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*.

B. ENERGY EFFICIENCY

PURA § 39.905 requires electric utilities reduce their annual growth in energy demand by at least 10% by January 1, 2004.[66] To achieve this goal, utilities must provide incentives to energy efficiency service providers for improvements in energy efficiency. The mechanisms for achieving the energy efficiency improvements are market-based standard offer programs and limited market transformation programs.

Under a standard offer program, a utility offers a standard incentive amount for energy and demand savings for the installation of measures to make a customer's energy consumption more efficient. The type of measures to be installed is the decision between the energy efficiency service provider and the customer. Retail electric providers and large commercial customers (acting as their own energy efficiency services provider) may participate in the program as well. The project must result in energy and demand savings, and the measures must produce savings for at least ten years. The incentive typically does not cover the full cost of the measures that are installed, and the customer usually must make a contribution.

There are standard offer programs available for all customer classes. Typically, projects for residential customers involve insulating homes or upgrading heating or cooling systems. The types of projects carried out for commercial or industrial customers may be as complex as redesigning manufacturing processes or as simple as replacing lighting systems.

Under a market transformation program, an energy efficiency service company conducts a program, funded by a utility, to bring about permanent changes in the way energy efficiency products or services are offered and used in the market. Examples of such programs in Texas include giving retail customers a rebate to cover the difference in price between a high efficiency air-conditioner instead of a standard model. Also, the Energy Star New Homes program is a market transformation program that encourages builders to increase the efficiency of new home construction, and allows the builder to use the Energy Star certification as a marketing tool with new home buyers.

On January 1, 2002, all utilities subject to customer choice were required to implement standard offer or market transformation programs. The costs of the programs are funded through the TDU's transmission and distribution rates. Utilities not subject to customer choice have voluntarily adopted the programs. In the case of EGSI and SWEPCO, where customer choice has been delayed, these utilities have proceeded to implement the programs to ensure that they will meet the statutory goal once customer choice is introduced in their service areas.

The Commission has approved statewide templates for standard offer and market transformation programs. In addition, the Commission has adopted standardized savings estimates for the most common energy-efficiency measures and adopted the International Measurement and Verification Protocol for use in verifying energy savings of other measures. The program templates describe the target customer sectors, the incentive levels, and the required measurement and verification procedures. Utilities may develop other programs, but

---

[66] Demand is the rate at which energy is delivered to loads and scheduling points by generation, transmission, or distribution facilities. Electric demand is expressed in kilowatts.

the approval of the templates is intended to provide utilities with a number of program options, without incurring additional costs for the development of the program.

Table 15: Energy Efficiency Programs—Funding, Demand, and Energy Savings

Program Year 2001 – Actual Measure Energy and Demand Savings

Customer Class	Funding	MW	MWh
Hard to Reach (<200 of poverty line)	$6,801,750	3	58,356
Residential/Small Commercial	$15,776,167	14	65,967
Large Commercial/Industrial	$16,120,842	24	103,527
TOTAL	**$38,698,759**	**41**	**227,850**

Program Year 2002

Customer Class	Funding	MW	MWh
Hard to Reach (<200 of poverty line)	$4,324,941	3	13,401
Residential/Small Commercial	$18,666,315	31	98,483
Large Commercial/Industrial	$15,073,355	33	132,421
TOTAL	**$38,064,611**	**67**	**244,305**

Program Year 2003

Customer Class	Funding	MW	MWh
Hard to Reach (<200 of poverty line)	$8,177,679	6	29,455
Residential/Small Commercial	$34,655,109	46	204,001
Large Commercial/Industrial	$28,668,697	57	269,763
TOTAL	**$71,501,485**	**109**	**503,219**

Program Year 2004

Customer Class	Funding	MW	MWh
Hard to Reach (<200 of poverty line)	$8,465,353	6	28,972
Residential/Small Commercial	$34,564,555	46	202,657
Large Commercial/Industrial	$28,761,365	59	265,799
TOTAL	**$71,791,273**	**111**	**497,429**

Program Year 2005

Customer Class	Funding	MW	MWh
Hard to Reach (<200 of poverty line)	$8,280,670	6	33,102
Residential/Small Commercial	$32,631,686	47	226,916
Large Commercial/Industrial	$26,904,998	60	295,564
TOTAL	**$67,817,354**	**113**	**555,582**

C. GOAL FOR NATURAL GAS

PURA § 39.9044, *Goal for Natural Gas*, states the intent of the Legislature that at least 50% of new generating capacity (in MWs) installed in Texas, excluding renewables, use natural gas as its primary fuel. Since January 1, 2000, 100% of the new non-renewable generating capacity added in Texas has been gas-fired. The total gas-fired capacity added in Texas since January 1, 2000 has been 16,800 MW, or about 19% of total capacity in the state by the end of 2002. The following chart shows the installed generation mix in Texas.

Table 16: Generation Mix in Texas

Resource	% of Generation Capacity
Natural Gas	68.9%
Coal & Lignite	23.3%
Nuclear	5.6%
Wind	1.1%
Hydro	0.7%
Other	0.4%
Total	**100%**

SOURCE: PUC Market Oversight Division.

Because market forces have been adequate in meeting the intent of PURA § 39.9044, *Goal for Natural Gas*, the natural gas credit trading program developed in P.U.C. SUBST. R. 25.172, *Goal for Natural Gas*, has not been triggered. The Commission projects that market forces will be sufficient to promote the development of new gas-fired generating capacity in Texas for the foreseeable future.

D. DISTRIBUTED GENERATION

PURA § 39.101(b)(3) states that all customers are entitled to on-site distributed generation. In response to this directive, the Commission has developed and implemented nationally recognized rules governing standard interconnection requirements and pre-certification criteria for distributed generation units. Fourteen new distributed generation facilities were interconnected in 2001 with capacity of 37,885 kW. The addition of these units results in a total of 75 distributed generation units installed in Texas, with a total capacity of 212,610 kW. Another 15 units with 49,672 kW of capacity were awaiting interconnection at the end of 2001. The majority of these units are gas or diesel engines.

Fuel Cells. Fuel cells are small-scale distributed generation units that utilize an electrochemical process that combines hydrogen and air to create electricity. As opposed to combustion engines that emit a variety of pollutants, the only by-product of a fuel cell that runs on hydrogen is water and trace amounts of nitrogen oxides, although carbon dioxide can also be released depending on the process used to obtain the hydrogen. Some fuel cell technologies also produce heat, which can further reduce reliance on the electrical grid or natural gas. Fuel cells have multiple applications, including stationary power sources and automotive uses.

Fuel cells potentially provide an environmentally friendly and efficient method to relieve transmission congestion and address pollution concerns in the major urban areas of Texas. However, commercial fuel cells today cost around $4,000 per kW of capacity, excluding site costs. This is dramatically more expensive than other sources of new generation, including combined cycle gas turbines.

HB 2845, passed by the 77th Texas Legislature, tasked the State Energy Conservation Office (SECO) in the Comptroller's Office with creating a fuel cell commercialization advisory committee to explore methods to encourage commercialization of fuel cells and to make Texas a leader in the development of this new technology.

The Commission has participated in the HB 2845 activities. Additionally, Commission staff has developed a white paper outlining possible legislative policies that could further the development of fuel cells as a viable generation resources in Texas. The white paper is Appendix 6.

E. CUSTOMER PROTECTIONS

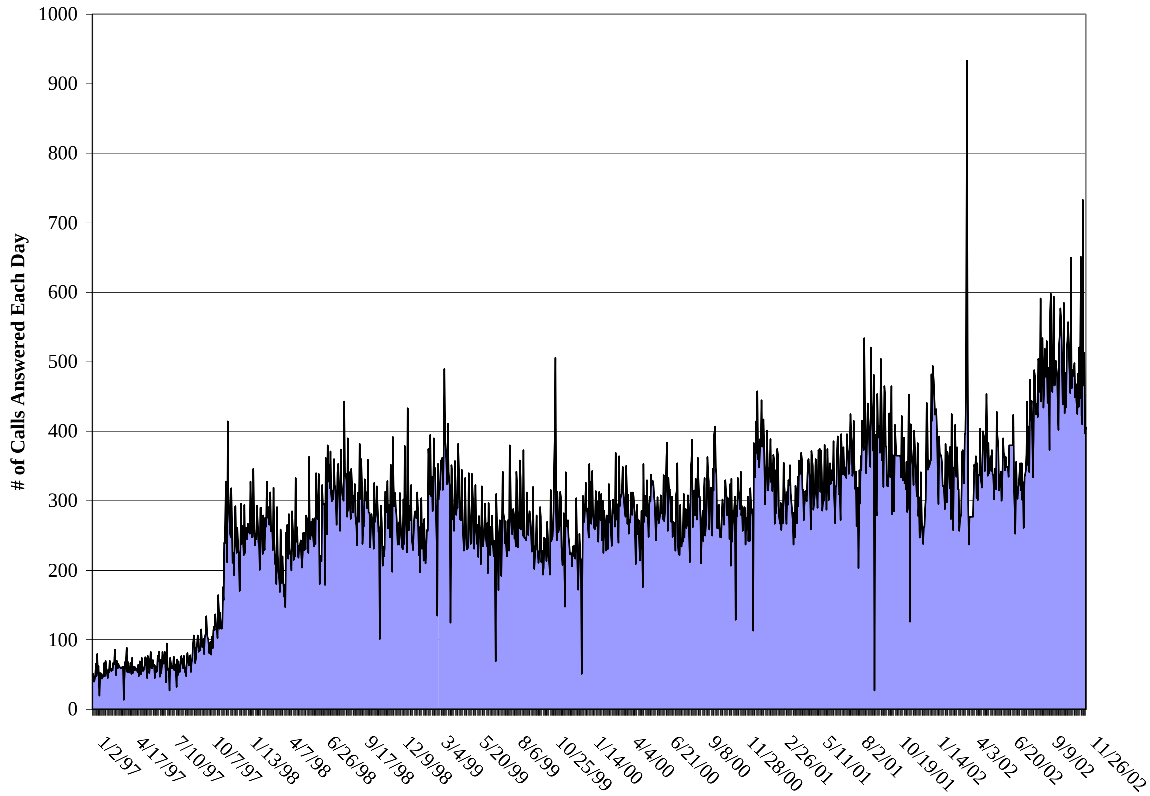
PURA § 39.101(f) required the Commission to adopt rules regarding customer protections to ensure that at least the same level of customer protection against potential abuses and the same quality of service that existed in December 1999 is maintained in the restructured electric industry. The Commission adopted customer protection rules for the competitive retail market in December 2000.

1. Complaint Handling

The Commission's Customer Protection Division (CPD) was created in 1997 in response to an increased need to respond to complaints against telecommunications and electric service providers. CPD answers public inquiries through a toll-free customer assistance hotline, investigates and resolves complaints, and develops and disseminates customer education material. Since its creation, CPD has increased in size to 15 complaint investigators, 11 call center representatives, and five information and education employees. CPD also oversees the Relay Texas program, the statewide telephone interpreting service for the hearing- and speech-impaired.

CPD receives complaints and inquiries by mail, fax, e-mail, and telephone. The average time to investigate and resolve a customer complaint is 38 days. Even given the large volume of calls received by the CPD each day, CPD staff is handling customer complaints in a timely manner.

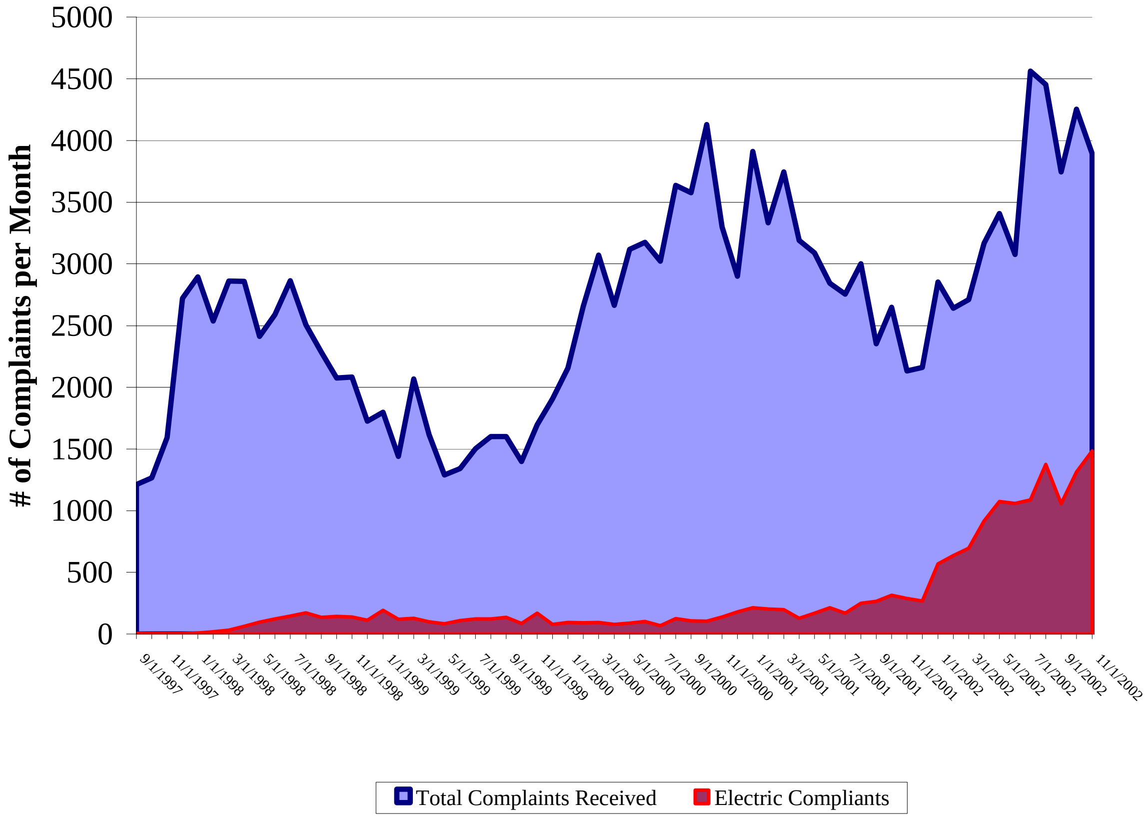
Figure 24: Number of Calls Answered Each Day in Customer Protection



SOURCE: PUC Customer Protection Division.

Complaint volumes have steadily increased since September 1997, especially over the past two years. In 2002, the Commission increased the number of customer service employees to handle this increase in the number of inquiries and complaints. While the majority of complaints are telephone service related, there has been a noticeable increase in complaints related to electric service since the beginning of 2002. A large increase in July 2002 was attributable to the effective date of the "No-Call" List.

Figure 25: Total Complaints Received by PUC

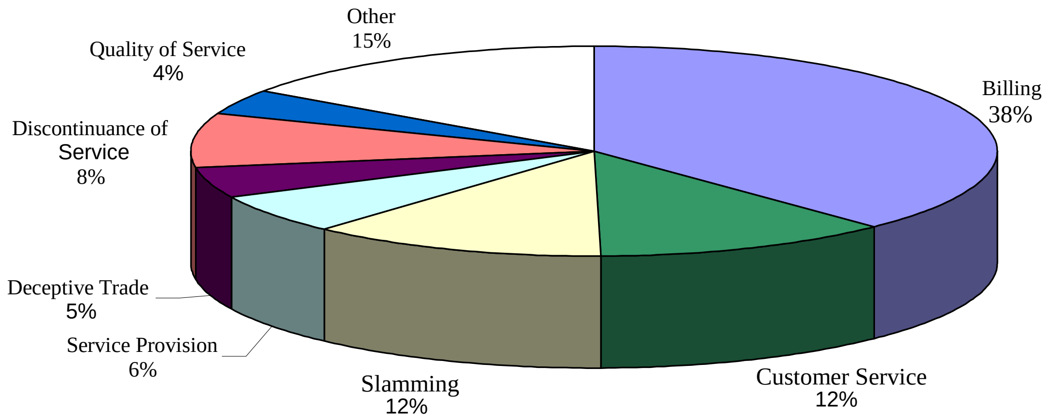


SOURCE: PUC Customer Protection Division.

2. Electric Service Complaints

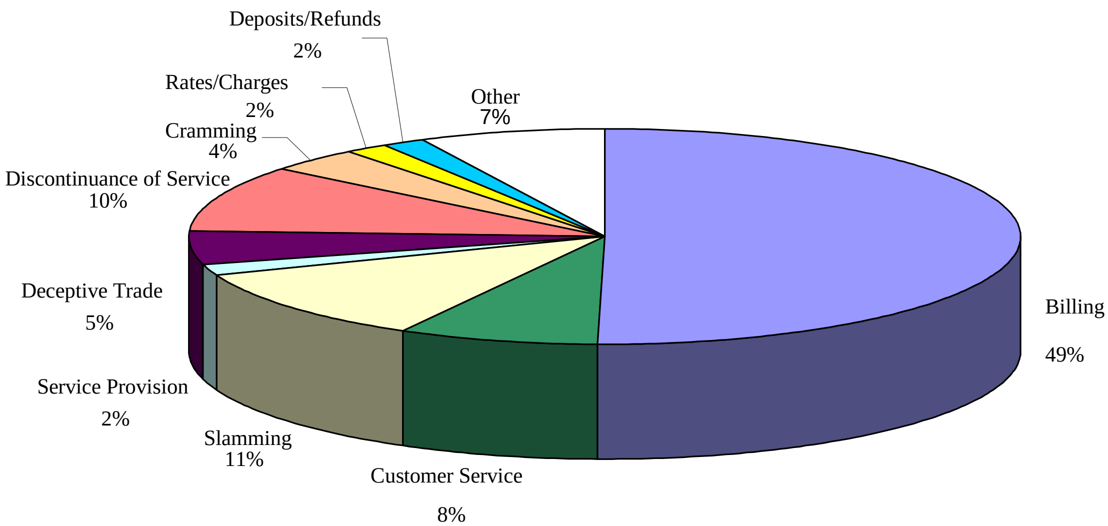
The majority of electric-related complaints are billing related, with customer service and slamming complaints following. This increase in complaints related to electric service was not entirely unexpected, as many REPs had never done business under Commission rules before, and existing Commission rules related to customer protections were revised to accommodate the new market structure. Also, many of the electric complaints concerned the transition issues surrounding the switching, move-in, and billing issues discussed in Section IV.C. of this report. For example, many complaints regarding slamming were related to the transfer of customers from New Power to Reliant or TXU, or were caused by the confusion surrounding the technical problems experienced early in 2002 relating to the switch process.

Figure 26: Composition of Electric Complaints Received, Sept. 2001- August 31, 2002



SOURCE: PUC Customer Protection Division.

Figure 27: Composition of Electric Complaints Received, Sept. 2002-November 30, 2002



SOURCE: PUC Customer Protection Division.

Complaint Processing Agreement for Centrica. The Commission has recently approved a settlement that would transfer ownership of the affiliated REPs serving price-to-beat customers of American Electric Power (AEP) to Centrica, PLC (Centrica), which does business in Texas as a REP under the name Energy America. Several parties in the proceeding expressed concerns about allegations that Energy America is engaged in deceptive or misleading marketing, especially with respect to door-to-door marketing. As part of the settlement and approval of the transfer, Centrica agreed to a process that would expedite the review and resolution of complaints, and assess pre-specified penalties for verified, confirmed customer complaints. Centrica also agreed to use specific procedures, and an independent third-party arbiter to determine whether complaints are valid.

Penalties for complaints due from Centrica in any given calendar month are to be calculated on a cumulative basis by applying to each valid complaint a prescribed payment amount. Specifically, the Centrica REP will pay a penalty of $2,000 each for the fifth through tenth confirmed complaints in a calendar month, plus a penalty of $1,500 each for the eleventh through twentieth confirmed complaints in a calendar month, plus a penalty of $1,000 each for the twenty-first and all subsequent confirmed complaints in a calendar month. No payments are required if four or fewer confirmed complaints are received in a calendar month. The penalty matrix approved by the Commission is shown below.

Table 17: Centrica Penalty Matrix

No. of Confirmed Complaints for the Calendar Month	Payment Per Confirmed Complaint
0-4	No Payments Due
5-10	$2,000
11-20	$1,500
>20	$1,000

SOURCE: *Notice and Request of Mutual Energy CPL, LP and Mutual Energy WTU, LP for Approval of Changes in Ownership and Affiliation*, Docket No. 25957, Order (December 20, 2002).

The Commission believes that this model may serve as an innovative new way to address customer complaints and assess penalties for violations of Commission rules.

3. Enforcement Actions

In many cases, customer complaints are solved through the informal complaint process, obviating the need for a formal contested proceeding. Also, Commission staff routinely monitors service providers' compliance with Commission rules, and in most cases, service providers quickly remedy non-compliance when it is brought to their attention. The Commission also utilizes calls and complaints received in its call center in assessing whether a more formal investigation and/or enforcement action is warranted against a particular service provider.

The Executive Director of the Commission initiated a formal enforcement action against The New Power Company for violations of the Commission's rules regarding bill format. Specifically, New Power did not include certain information, such as consumption and the electric service identifier number on bills, and had inappropriately reflected some charges on the bills. The enforcement action has tentatively been settled as part of a broader settlement regarding New Power's exit from the Texas market.

The Executive Director has also initiated enforcement action against 19 electric providers seeking over $250,000 in total penalties for their failure to comply with the Commission's rules regarding complaint processing.[67] These enforcement actions are pending at the time of this report. The Commission staff has also opened formal investigations into the compliance of REPs and TDUs with Commission rules relating to bill issuance and the correction of previously underbilled amounts (including not issuing a bill at all).

4. Texas "No-Call" Lists

On January 1, 2002, Texas joined 24 other states with statutory "no-call" lists intended to shield telephone customers from unwanted telemarketing sales calls. Texans may now register their residential telephone number for one or both of two "No-Call" Lists maintained by the Texas PUC. Customers may place their name, address, and telephone number on these lists to identify themselves as individuals who do not want to receive unsolicited telemarketing calls at home.

General "Do Not Call" List. The general, statewide "Do Not Call" List was established by H.B. 472 enacted by the 77th Legislature in 2001, and applies to all telephone marketers operating in Texas. A registered residential telephone number(s) remains on the list for three years. Business telephone numbers cannot register for this list.

"Electric No-Call" List. The "Electric No-Call" List was established by SB 7, the electric restructuring utility bill enacted in 1999. The "Electric No-Call" List prevents calls only from Retail Electric Providers and telemarketers calling about electric service. Both businesses and residential numbers can be added to the "Electric No-Call" List, and numbers remain on the list for five years.

"No-Call" Registration. The first registration period for the "No-Call" Lists closed on March 27, 2002. The first "No-Call" List was published on April 1, 2002, and included 386,046 telephone numbers. The second registration period closed on June 26, 2002. The second list was published on July 1, 2002, bringing the total registered telephone numbers to 658,749. As of November 30, 2002, over 769,540 telephone numbers have been included in the no-call registry.

Complaints. The Texas PUC is authorized to investigate complaints and to assess administrative penalties for violations of the Texas "No-Call" Lists involving all entities except state licensees.[68] Since July 1, 2002, the Texas PUC has received close to 4,965 contact related to the no-call lists. The Commission is currently investigating these complaints to determine if formal enforcement action is warranted.

---

[67] *Generic Proceeding of the Legal & Enforcement Division to Impose Administrative Penalties Against Electric Utilities and Providers (4th Quarter of 2002),* Docket No. 27082 (pending).

[68] TEX. BUS. & COM. CODE ANN. § 43.102(b).

F. ENVIRONMENTAL GOALS

When SB 7 was enacted there was a growing concern about air quality in the major metropolitan areas of the state, and several provisions were included in the law to help improve the air quality in Texas cities. SB 7 includes a renewable energy mandate, an energy efficiency program, and a mandate for reductions in air emission from the utility power plants that were built before the Federal Clean Air Act became effective.

The air emissions reductions are prescribed by PURA § 39.264 and require the utilities to reduce emissions of nitrogen oxide (NOx) by 50% and sulfur dioxide by 25% by May 1, 2003. Additional emission reductions are being required because the air quality in the major cities is not in compliance with the national standards under the Clean Air Act. Since 1999, the Texas Natural Resources Conservation Commission (now the Texas Commission on Environmental Quality) has adopted State Implementation Plans to bring the air in the Houston-Galveston and Dallas-Fort Worth areas into compliance with the national standards by 2007. These plans require significant reductions in the emissions from all sources in these areas, including utility power plants. The Houston plan, for example, calls for 80% reductions in NOx emissions from power plants.

To comply with the emission reduction mandate in SB 7, utilities have developed plans to retrofit or shut down their older power plants. Competitive forces are also working to reduce emissions from power plants. The new power plants that have been built in Texas since the late 1990s are more fuel-efficient than the older generation of the utilities and are required to have control technologies to reduce their NOx emissions. Power production from the new, clean, efficient generating plants is displacing production from the old, dirty, inefficient plants. Environmental Defense has estimated that Texas electric generating capacity will increase by 36% in the period 1999 to 2007, while total NOx emissions will decrease by more than 40%.[69]

G. BENEFITS OF ELECTRIC COMPETITION TO THE TEXAS ECONOMY

Electric competition not only provides benefits in terms of customer choice, it is also providing the state with tangible economic benefits in the form of both new job creation and opportunities to develop new businesses.

A recent study by Dr. Ray Perryman quantified some of the initial economic benefits from electric restructuring for the January 2002 through April 2002 time period.[70] This study includes an estimate of the total savings achieved by customers as a result of electric competition and the implementation of SB 7, as well as the economic benefits of consumers redeploying those savings to the purchase of other goods and services.

---

[69] *The Texas Energy Model: Providing Energy, Protecting the Environment*, Environmental Defense, Summer 2001

[70] *The Truth About Electric Competition in Texas: An Early Assessment*, The Perryman Report, May 2002, published by the Perryman Group.

The study estimated total benefits to the Texas economy from consumer savings at:

- $716 million in annual total expenditures;
- $350 million in annual gross area product;
- $213 million in annual personal income;
- $38 million in annual retail sales; and
- 5,283 permanent jobs.[71]

Additionally, the study also estimated the aggregate effects of power plant development activity associated with competition since SB 7 was enacted. These benefits were found to be:

- $32.4 billion in annual total expenditures;
- $16.1 billion in annual gross area product;
- $10.7 billion in annual personal income;
- $4.1 billion in annual retail sales; and
- 285,359 person-years of employment.[72]

A competitive electric market can also become the source for new, clean energy research and development and for innovative new products and services. The State's success with renewable energy shows that a competitive market can encourage the development of a new, clean source of energy supply, such as wind power, and a new innovative product offering, green energy. Similarly, the Texas electric market may spur the development of other innovative energy sources and products, such as energy storage, real-time demand responsive programs, and fuel cells research and development.

The Dallas Morning News recently pointed out that electricity restructuring provides an opportunity for the state to leverage its traditional energy industry position into leadership in creating new and innovative sources for energy:

> "Texas should be the undisputed leader of the effort to develop clean alternatives to petroleum, coal and nuclear power to free the United States from its overreliance on unstable foreign energy suppliers".[73]

Some groups have begun to see the opportunity to create a center of energy innovation in Texas. The Austin Clean Energy Initiative, for example, recently released an extensive report showing that Texas is well positioned to become a world leader in energy technologies. The report identified 335 enterprises engaged in energy innovation in Texas, 80 of them in Central Texas.[74]

The report identified that the Central Texas corridor possesses a combination of factors that could lead to the development of a new Texas clean energy industry, including government support, well established infrastructure, rich renewable resources, the increasing synergies between clean energy and information technology, the University of Texas at Austin's research facilities, and a well-educated workforce.

---

71 *Id*. at 5.

72 *Id*. at 5.

73 "The New Energy: Texas should lead the way" Dallas Morning News, March 18, 2002.

74 Austin Clean Energy Initiative, http://www.austincleanenergy.org/report/AceReport.pdf.

VI. EMERGING ISSUES

A. FINANCIAL CONDITION OF ENERGY COMPANIES

For the majority of the time while SB 7 was being enacted and implemented, the financial condition of the electricity industry was strong. During this period, Wall Street was particularly optimistic about the prospects of companies that were perceived to be positioned to succeed in a competitive market. Developers of merchant power plants, such as Calpine, and companies with significant power trading business, such as Enron and Dynegy, had favorable bond ratings and were typically identified by stock analysts as sound companies with strong growth prospects.

A number of events in the industry have led to the reversal of this situation, so that Enron and the New Power Company are now in bankruptcy, and even large diversified companies have reduced or suspended the payment of dividends and suffered declines in their stock prices and bond ratings. There are a number of reasons for the evaporation of investor confidence in the energy industry, including:

- The California energy crisis, which resulted in the bankruptcy of one of the largest utilities in the state;
- The revelation of the complex organizational arrangements and inflated revenues at Enron;
- The revelation of wash trades and inflated revenues at a number of energy companies;
- Efforts by the State of California and utilities in the West to recover damages for allegedly illegal practices of companies that produced and traded power in the West and to renegotiate contracts that were entered during the height of the California crisis;
- Declining demand for power and wholesale power prices as the U.S. economy softened;
- Extensive debt financing of power plant construction; and
- Declining power prices in foreign markets where US companies had energy investments.

The most direct and obvious implications for the Texas retail market have been a downturn in the construction of new generation facilities and the exit of REPs from the market. Generation adequacy is discussed in Section VI.C and the exit of retailers from the market is discussed below.

It is also likely that there are other consequences that are not readily apparent, such as an unwillingness of new REPs to enter the Texas market or unwillingness of larger REPs to expand their operation to the smaller service areas. Tight credit is also likely to make the REPs cautious about developing new rate offers or innovations like energy-efficiency programs that could increase customers' benefits. The collapse of Enron, the California energy crisis, and the evaporation of investor value in companies that were seen as leaders in the competitive energy industry has also undoubtedly been an important contributor to the failure of new states to introduce retail competition. If more states adopted retail competition, it would provide a broader customer base for the competitive REPs in Texas and thus would enhance competition here. It is also possible that the worst of the downturn in the energy industry has not yet occurred. A number of energy companies are in serious financial straits, and the failure of one of them would, in the short term, exacerbate the condition of other companies to which it has outstanding obligations. Additional business failures also hold the prospect of eliminating competitors at both the wholesale and retail level, leading to additional concentration in the market.

In Texas, the first immediate impact of the industry's reversal of fortune was the bankruptcy of Enron Energy Service (EES). EES was among the units of Enron Corp. that filed for bankruptcy protection in the fall of 2001. EES served a small number of customers during the pilot project, and returned those customers to TXU in December 2001. EES also had approximately 17,500 contracts with customers for electric service to commence in January 2002. The customers were generally small commercial customers eligible for the price to beat, and had entered into fixed price contracts with terms of up to 60 months. EES never submitted switch requests to ERCOT and never provided retail service to the customers.

In response to concerns regarding EES's ability to operate as a REP and provide adequate service to customers, the Commission staff filed a petition to revoke EES's REP certificate. EES pursued an agreement to sell the customer contracts to another REP that was awaiting certification. That agreement, subject to the Bankruptcy Court's approval, would have provided the customers with the same prices and terms that they had negotiated with EES, and made them whole for the economic value of the contracts. However, before the transaction could be closed, wholesale power prices had risen such that the customer contracts were uneconomic for the buyers. As a result, no sale was made, and the customers continued to be served by the affiliated REP (unless they chose another REP).

EES's certificate was subsequently revoked by the Commission. Due to the bankruptcy filing and subsequent inability of EES to find a buyer for the customer contracts, the customers never realized the economic benefit of the contracts they had negotiated with EES.

The New Power Company (New Power), a REP serving residential and small commercial customers, filed for bankruptcy protection in June 2002, primarily due to the company's relationship with Enron. Prior to bankruptcy, New Power had acquired and was serving approximately 80,000 residential and small commercial customers.

New Power entered into agreements with TXU Energy Services (TXU Energy) to transition New Power's customers in the Houston area to TXU Energy at rates that were lower than the rates that would have been charged by the POLR, and generally comparable to the price-to-beat rates of the affiliated REP in the area, Reliant Energy. New Power entered into a similar agreement with Reliant Energy resulting in the transfer of New Power customers to Reliant Energy in the Dallas/Ft. Worth area. New Power, Reliant Energy, and TXU Energy requested that the Commission review the transition agreement to ensure compliance with the Commission's customer protection rules. The Commission delegated that authority to the Executive Director of the Commission, and the agreements were found to be consistent with applicable Commission rules. The Bankruptcy Court subsequently approved the transition agreements.

In August 2002, New Power requested that the Commission permit it to relinquish its retail electric provider certificate upon the conclusion of its business in Texas. During the course of that proceeding, concerns were raised by the Commission staff, the Office of Public Utility Counsel, and other consumer groups that New Power's plan to exit the Texas market might not provide adequate customer complaint resolution and customer protection provisions. Additionally, it was determined that New Power had issued approximately 40,000 bills to customers that were non-compliant with Commission rules, leading to the initiation of an enforcement action by the Commission staff.

New Power, Commission staff, and consumer groups entered into a settlement, ultimately approved by the Commission and the Bankruptcy Court, which established standards for resolution of customer complaints, final billing of former New Power customers, other customer protections, and tentative resolution of the pending enforcement action. At the time of the writing of this report, the Commission was monitoring New Power's compliance with the settlement agreement and Commission rules.

Both the EES and New Power cases, along with bankruptcy proceedings involving telecommunications providers, have required active Commission involvement, assisted by the Attorney General's office, to ensure that retail customers continue to receive service in compliance with the Commission's customer protection rules and service standards. The Commission and Attorney General's office have vigorously asserted the Commission's and State of Texas's rights under the 11^{th} amendment to the United States Constitution to exercise its police and regulatory powers in order to assure that providers continue to comply with all Commission rules and Texas law.

However, the Commission cannot order economic compensation to retail customers without Bankruptcy Court approval. Customers who are economically affected by the bankruptcy of their provider are generally considered unsecured creditors, and as a result, they are required to file claims in the Bankruptcy Court and may not receive the economic benefit of contracts that they executed with their provider. In the case of residential and small commercial customers, it is unlikely that these customers will have the ability or resources to file and pursue claims at Bankruptcy Court proceedings that in many cases occur in other states. In the New Power bankruptcy proceeding, the Office of Public Utility Counsel, as the statutorily authorized representative of residential and small commercial customers, filed a class-proof-of-claim in order to preserve the value of inducements (frequent flier miles, incentive payments, gift certificates, etc.) that New Power used to solicit customers.

Commission rules also require that, when practical, REPs give customers 30 days notice of the transfer of their service to another REP if they are abandoning the market and transferring the customers to the POLR. The Commission's experience to date is that this requirement is often not practical to meet. In the event a REP abandons the market with no notice, the customers will be transferred to the POLR in order to ensure continued service. However, it is important to note that transfer to the POLR is truly a "last-resort" event, and the REPs that have exited the market have attempted to sell or transfer customer contracts to another REP as a way to extract the value of those contracts.

The exit of providers who encounter financial or other difficulties is a reality of competitive markets. While such events are challenging to address and resolve with the best possible resolution for retail customers, the Commission, in association with the Attorney General's office and the Office of Public Utility Counsel, expects to be able to continue to ensure compliance with the customer protections rules for customers of financially-strapped REPs.

B. STRANDED COST TRUE-UP PROCEEDINGS

1. Generation Asset Valuations

As discussed in Section III.B.1, "stranded costs" are the difference between the net book value of generation plants and the market value of the assets. Electric utilities (and their affiliated power generation company) are permitted to recover all of their net, verifiable, and non-mitigable stranded costs through a non-bypassable "competition transition charge" (CTC).

Initial estimates of stranded costs were made during the cost separation cases filed by the utilities in April 2000. In large part due to high estimates of natural gas prices,[75] the Commission found initial estimates of stranded costs to be negative, that is, estimates of the market value of the generation resources exceeded the net book value of the assets. As a result, the Commission did not establish interim CTCs and instead ordered the utilities to begin returning stranded cost mitigation to customers as a credit to non-bypassable charges (excess mitigation credit (EMC)). The following table is a summary of the estimates of stranded costs made during 1998, and estimates made as part of the cost-separation proceedings.

Table 18: Summary of Stranded Cost Estimates

Utility	Stranded Costs Estimated in the 1998 ECOM Report	Stranded Costs Estimated in the 2001 UCOS Orders
TXU	$1,058 million	-$2,763 million
Reliant	$1,249 million	-$2,627 million
CPL	$1,704 million	-$615 million
TNMP	$176 million	-$0.5 million
Entergy	$203 million	$0 (per settlement)
TOTAL	**$4,390 million**	**-$6,005.5 million**

SOURCE: PUC Financial Review Section, ECOM model.

[75] Stranded costs are predominately related to nuclear-generation assets due to the high capital costs of building those plants. Market prices in ERCOT are predominately set by natural gas-fired generation. As natural gas prices rise, the market price of electricity rises. As a result, nuclear assets recover more of their fixed costs through the market, and stranded costs are lowered. Natural gas prices for 2002 were estimated to be $3.33 per MMBtu.

Affiliated power generation companies (PGCs) are currently required to finalize their stranded cost estimates through one or more of five methods outlined in PURA § 39.262(h).[76] These methods are:

- **Sale of generation assets.** Affiliated PGCs may conduct a bona-fide third party sale under a competitive offering in order to establish the market value of their generation assets;
- **Stock valuation.** Affiliated PGCs may transfer generation assets to a separate affiliated or non-affiliated company with 51% of the stock held by public investors;
- **Partial stock valuation.** Affiliated PGCs may transfer generation assets to a separate affiliated or non-affiliated company with 19%-51% held by public investors;
- **Exchange of assets**. Affiliated PGCs may transfer their generation assets in a bona-fide third party exchange transaction in order to establish the market value of the assets; and
- **Use of ECOM model.** Unless the affiliated PGC uses methods (2) or (3) for all of its remaining generation assets, nuclear assets will be valued using the ECOM method, with updates to the model to reflect current market conditions.

As discussed earlier in this report, TXU and Entergy have both agreed to forego further stranded cost recovery, and will not be conducting true-up proceedings as a result of these settlements. Reliant, TNMP, and CPL are required, barring additional settlements, to finalize their stranded costs using the above methods.

The energy industry in general (and merchant generation companies in particular) is currently operating in a market characterized by uncertainty, overcapacity, and severe downward pressure on wholesale prices. Much of this environment can be attributed to concerns about accounting practices in the wake of the collapse of Enron (and other energy traders) and lowered growth forecasts for both additions of generation capacity and energy trading activities. The nationwide economic downturn has also reduced forecasts of demand growth for the immediate future as larger customers curtail operations. Investors and capital have significantly withdrawn from the energy industry.

It is likely that unless the level of uncertainty and unease of investing in energy-related concerns decreases in the next year, investor interest in either the outright purchase of generation assets or purchase of stock of stand-alone generation companies may be very low. When combined with the fact that the ERCOT market is projected to have reserve margins at least in excess of 15% through 2005, the market valuations of the affiliated power generation companies' assets may be significantly lower than previously thought.

Additionally, and of greater concern, is the possibility that the market will not appropriately or rationally value generation assets in coming years if industry-wide concerns

[76] TXU has entered into a settlement approved by the Commission that finalizes its stranded costs without the need to conduct a true-up proceeding (Docket No. 25230). The Commission's order approving the settlement is currently on appeal in Travis County District Court (*Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities, et.al., vs. Public Utility Commission of Texas*, No. GN2-02825 (345th Dist. Ct., Travis County, Tex. Aug. 16, 2002; *Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities vs. Public Utility Commission of Texas et.al.*, No. GN2-02824 (345th Dist. Ct., Travis County, Tex. Aug. 16, 2002)).

about accounting practices and the ability of generators to meet previously stated revenue forecasts remain. If so, it is possible that the valuation of generating plants will be very low allowing the affiliated PGC to securitize large amount of stranded costs. If the energy industry and power prices rebound in later years, the affiliated PGC may not only recover the costs of their investments through stranded cost charges that cannot be reversed, but may also recover those costs through normal market forces. This could give the affiliated PGCs an enormous competitive advantage over other generators; and it also could result in ratepayers paying both for high energy prices as well as previously determined stranded costs.

It is possible that a near-term rebound in the energy industry as a whole or increased natural gas prices will offset these downward pressures. Additionally, to the extent that a utility/affiliated PGC has not fully mitigated all of its potentially stranded costs, those costs will not be recoverable through a CTC. The following table summarizes recent sales of generation plants by utilities in Texas.

Table 19: Recent Sales of Utility-Owned Generation Facilities

Date of Sale	Generation Plant/Utility	Sale Price	Size of Plant(s)	Sale Price per kW
June 2002	TNMP One (Lignite fueled) (TNMP)	$120 Million	305 MW	$393/kW
December 2001	Mountain Creek/Handley (natural gas fueled) (TXU)	$443 Million	2234 MW	$190/kW
March 2001	Frontera (natural gas fueled) (AEP)	$265 Million	500 MW	$530/kW

SOURCE: PUC Market Oversight Division Analysis.

The Commission does not at this time recommend any Legislative changes to address these concerns, noting that stranded cost recovery was an integral part of SB 7. However, the Commission believes that the Legislature should be aware that the current climate in the financial sector may depress values of generation assets in the true-up proceedings resulting in negative impacts on the development of both the wholesale and retail markets in Texas.

2. Impact of True-up on Retail Prices

For non-price-to-beat customers and customers taking service under competitive contracts from non-affiliated REPs, changes in non-bypassable charges do not immediately affect retail prices for retail customers unless they are taking service under a contact that provides for a direct pass through of non-bypassable charges. If, instead, the customers are served under bundled, fixed price contracts, then they will likely not see changes in non-bypassable charges until their contract expires. For price-to-beat customers, changes in non-bypassable charges do not automatically result in a change in the price to beat. However, increases in non-bypassable charges will affect headroom, or the ability of non-affiliated REPs to price below the price to beat. The Commission does have authority under PURA § 39.202(k) to adjust the price to beat following the true-up proceedings.

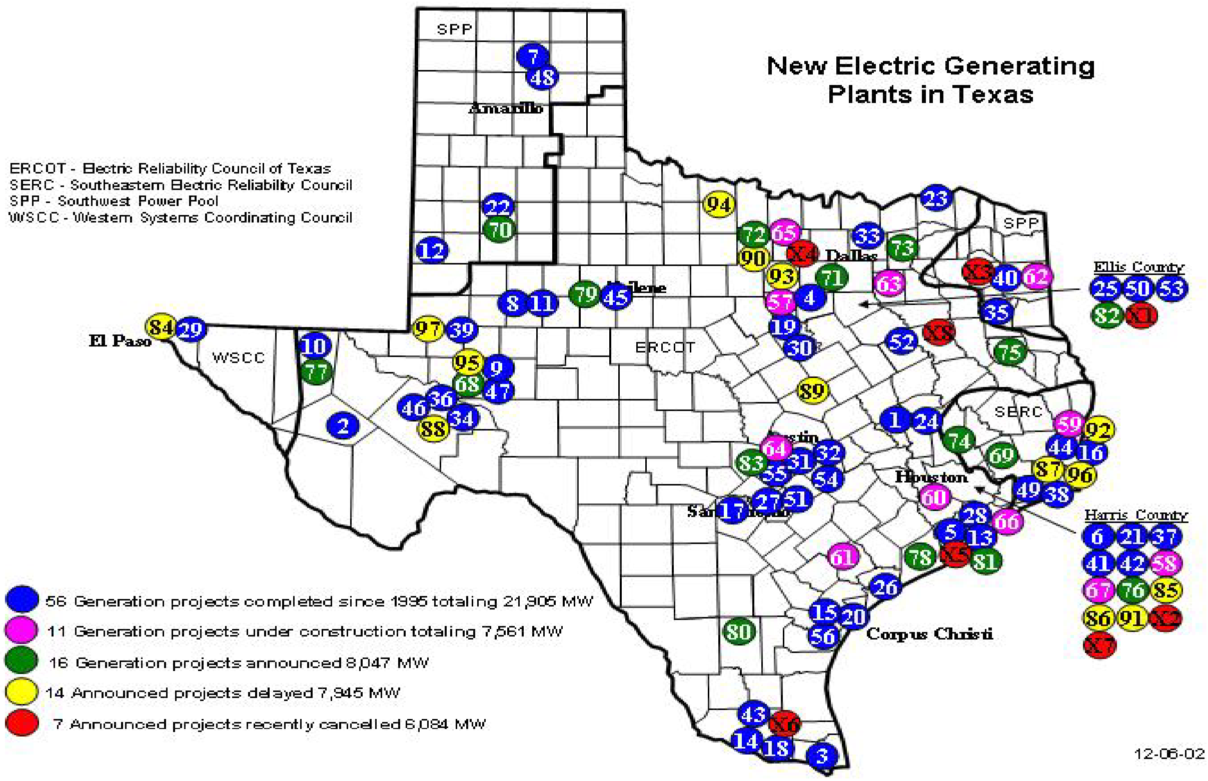
C. GENERATION ADEQUACY

As discussed in the *2001 Scope of Competition in Electric Markets Report*, many of the catastrophic events that have occurred in California over the past three years can be attributed to a deficiency in generation supplies. Conversely, a large part of the reason that new REPs have been able to economically compete against the price to beat in Texas is a comfortable excess of supply over demand.

A significant amount of new generating capacity has been added in the state since the wholesale market became competitive in 1995. About 22,000 MW of new capacity has been added since 1995, with another 7,500 MW under construction. Of this amount, more than 12,500 MW was added in 2001 and the first three quarters of 2002 alone. Another 7,000 MW is expected to be added by the end of 2003. The new capacity has contributed to current reserve margins well above the traditional standard of 15%.

Events in the national energy markets, including the Enron bankruptcy, tightening credit requirements for power plant developers, and slower demand growth due to the nationwide economic downturn, have slowed development and construction of new generation in all parts of the country. The following figure shows the location of new generating projects in Texas since 1995, but it also shows that more than 7,945 MW of announced capacity have been delayed and more than 6,000 MW have been cancelled. These delays and cancellations have affected capacity that would have come online in 2004 and later. A more detailed listing of the generation plants and their status is included in Appendix 7.

Figure 28: New Electric Generating Plants in Texas Since 1995



SOURCE: PUC Market Oversight Division analysis.

AEP and CenterPoint announced in fall 2002 that they plan to mothball 3,866 MW and 3,396 MW, respectively, of older, less efficient generating capacity, which will reduce the projected ERCOT reserve margins. Of this amount, 1,735 MW of the AEP capacity have been designated as reliability-must-run units by ERCOT and will remain in service. The CenterPoint capacity (3,396 MW) will be available for the summer of 2003, and may return to service after the winter of 2003. The following chart shows the most recent forecasts of expected ERCOT reserve margins, taking into account the mothballed generation.

Table 20: Forecasted ERCOT Reserve Margins

Year	Reserve Margin
2003	21.0%
2004	21.6%
2005	18.3%
2006	16.1%
2007	13.6%

SOURCE: ERCOT Capacity-Demand-Reserve Report.[77]

[77] The ERCOT Capacity-Demand-Reserve (CDR) Report is available at the following location: http://www.ercot.com/Participants/Accounting/Planned/Reports/Index.htm.

These projections are still conservative for several reasons. First, annual peak demand was actually lower in 2001 and 2002 than it was in 2000 because of cooler weather and the nationwide economic slowdown. Second, generating units under construction were not reflected in the margins unless the units had already signed interconnection agreements with ERCOT. Third, 3,068 MW of "switchable" units (*i.e.*, units that can send their capacity either to ERCOT or another region outside of ERCOT) were not reflected in the margins. Fourth, none of the existing or planned wind generation (1,035 MW) is included in the margins because of the unpredictability of the capacity available from wind. Also, none of the capacity of the DC Ties (856 MW), which could be used to import power into ERCOT, was reflected in the margins. Finally, this calculation does not include 1,728 MW of AEP capacity that AEP has mothballed on a long-term basis for economic reasons. This capacity could eventually be brought back online by AEP if market prices increase. However, if other AEP or CenterPoint mothballed units are shut down on a more permanent basis, projected reserve margins would fall.[78]

Under regulation, the Commission had the authority to require electric utilities to maintain an excess of 15% of generating capacity beyond that needed to serve firm load, but in a competitive market no specific level of reserve capacity is currently mandated. As discussed in Section III of this report, the Commission has opened a rulemaking project to determine what methods are needed to ensure adequate reserve margins that are still compatible with a competitive market structure. It is anticipated that a draft rule will be published by the end of the first quarter of 2003 and a final rule will be adopted by the summer of 2003.

The FERC is also considering proposals related to generation adequacy as part of the Standard Market Design rulemaking proceeding. If the FERC decides to adopt a generation adequacy requirement, the portions of Texas outside ERCOT will likely be required to comply with such a requirement.

D. MUNICIPAL REGISTRATION OF RETAIL ELECTRIC PROVIDERS

PURA § 39.358 permits municipalities to require REPs serving residents of their municipality to register with the municipality, and permits the municipality to assess an administrative fee. A number of cities have enacted ordinances requiring REPs to register with the cities. Currently, REPs have appealed 24 ordinances to the Commission due to concerns that the administrative fees required by the cities are not reasonable and that the ordinances attempt to introduce requirements beyond those required by the Commission for a REP to be certified. Several of the ordinances would result in dramatic increases in costs of operation to REPs in those cities.

[78] A small number of generating units were sold to new owners in 2001 and 2002, but these sales will not affect reserve margins as long as the units remain in service.

Several cities have argued that the Commission has no appellate jurisdiction over the ordinances. The Commission has rejected these arguments and found as a matter of law, the Commission does have authority to review and overturn ordinances that inhibit the competitive market. The Commission has found that the following provisions are *not* reasonable to include in municipal ordinances:

- Excluding any REP or type of REP from its registration requirement, unless the REP provides service only to the municipality's own electric accounts and not to its residents (because the municipality would already have the necessary contact information);
- Assessing fines or taking action against a REP by a municipality other than suspension or revocation;
- Requiring a REP to provide information other than that necessary to contact a REP and verify its standing with the Commission;
- Requiring a REP to pay per-customer registration fees or annual registration fees;
- Requiring REPs to file reports regarding complaints;
- Suspending or revoking a REP's registration and authority to operate within the municipality *unless* the Commission finds that the REP has committed significant violations of PURA Chapter 39 or rules adopted under that chapter; and
- Suspending or revoking the registration of the affiliated REP or POLR serving residents in the municipality.

The Commission has recently adopted a "safe-harbor" rulemaking related to these ordinances.[79] The rule lists a set of criteria and standards that, if met, would provide certainty to municipalities that their ordinance comply with PURA. The Commission believes that the combination of this rule, as well as processing of the appeals of existing ordinances, will resolve the majority of the issues surrounding these ordinances. However, these ordinances have the potential to dramatically increase the costs to REPs of operating in certain cities, and may prevent them from doing so, thereby thwarting the ability of some customers to have meaningful choices in electric providers.

E. TRANSMISSION INVESTMENT

A transmission constraint is a physical limitation in the transmission system that prevents the reliable delivery of electricity, and can prevent the more economic generation resources from being utilized in higher cost areas of the state. Transmission constraints prevent the most economic dispatch and use of generation resources in the state and result in a need to continue to operate less efficient generating units, and potentially permit generators in certain constrained areas to exercise market power.

New transmission capacity aids in the maintenance of reliable service, and allows new generation to be fully integrated into the grid, thereby providing for additional competition, and reduced electricity prices to consumers. While increased transmission investments increase the

[79] *Rulemaking to Establish Guidelines and Standards for Municipal Registration of Retail Electric Providers*, Project No. 25963 (pending).

cost of the delivery rates of the transmission and distribution utilities, it also reduces costs related to alleviating congestion and the operation of less efficient generation units.

In some areas of the country, transmission construction has not kept up with growth in demand for electricity and the construction of new generation facilities. In contrast, the Commission has assigned the responsibility for planning the regional transmission network to ERCOT, and PURA § 39.155(b) requires ERCOT to submit an annual report to the Commission identifying existing and potential transmission constraints and recommendations for meeting system needs. ERCOT also currently leads three regional planning groups (North, South, and West) to determine if additional actions are needed to resolve transmission constraints.

1. New Transmission Investment

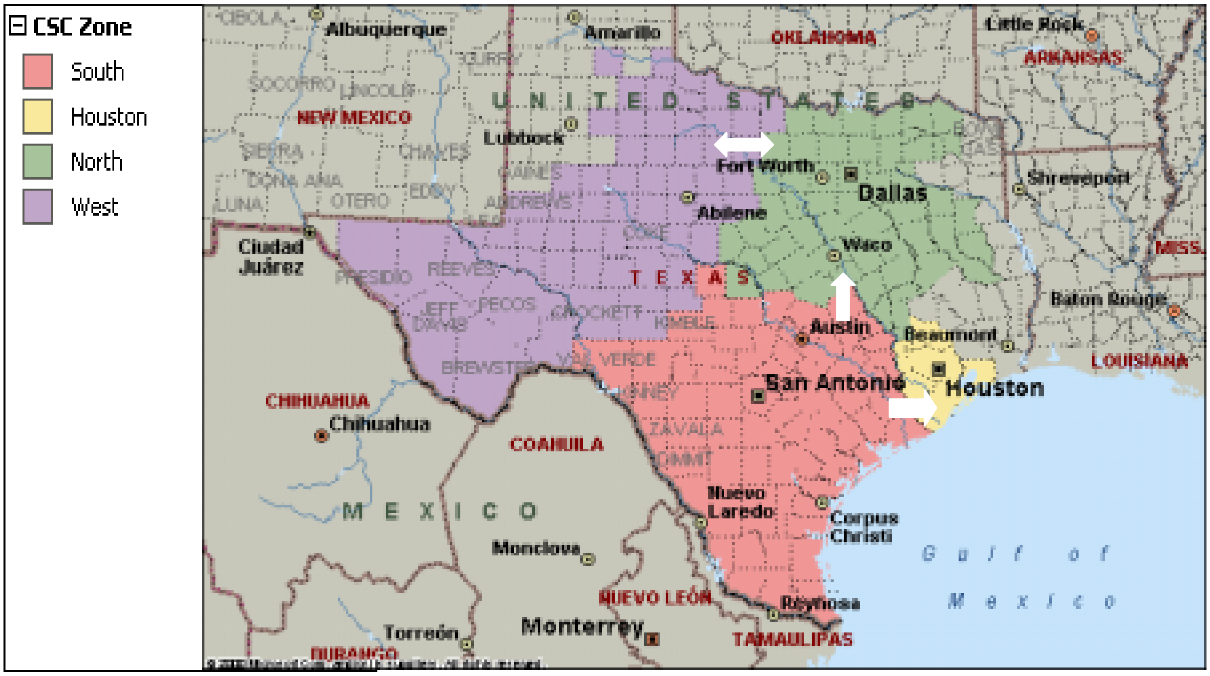
ERCOT has been conducting transmission planning on a regional basis since its reformation as an Independent System Operator in 1996. It issued its first report concerning transmission needs in the region in October 1998. The regional transmission planning conducted by ERCOT has been critical in identifying transmission needs and developing projects to meet these needs. During the period since ERCOT began its regional planning efforts, generation capacity increased by about 30%. About 18,000 MW of generating capacity was added, increasing the installed capacity from 59,000 MW to 77,000 MW, with ERCOT managing the process for connecting this generation capacity to the transmission network.

ERCOT has also identified projects that were needed to reduce the magnitude of transmission constraints or to improve system reliability. Unlike many areas of the country, the ERCOT region is an area where transmission facilities are being actively planned and built. Since ERCOT began conducting regional transmission planning, the Commission has licensed and utilities have built over 900 right-of-way miles of transmission facilities of various voltages in ERCOT (including over 400 right-of-way miles of 345 kV transmission facilities). In addition, there has been numerous other transmission projects built that have not required a PUC license. Major projects that have been identified by ERCOT and are now in service include the Limestone-Watermill project, which was intended to increase transmission capacity from South Texas to North Texas, and numerous projects in the Houston and Corpus Christi areas, which allow new generation projects in these areas to reliably deliver power to remote customers.

Even with these investments, ERCOT has identified three significant areas of transmission constraints for 2003:

- West Texas to North Texas;
- South Texas to North Texas; and
- South Texas to Houston.

Figure 29: Map of Electric Reliability Council of Texas (ERCOT)



The costs of alleviating these transmission constraints, and others, exceeded $250 million between July 31, 2001 and May 31, 2002. The $175 million of congestion costs related to commercially significant constraints is not expected to re-occur because of the change in the method of assigning those costs.

Table 21: Summary of Congestion Costs (In Thousands)
July 31, 2001 through May 31, 2002

Cause	Type	Cost
CSC Congestion	Balancing Energy Service	$174,555
	Replacement Reserve Service	$9
Local Congestion	Local Balancing Energy Service	$1,737
	Out-of-Merit Energy	$33,041
	Out-of-Merit Capacity	$40,661
Total		**$250,003**

SOURCE: Electric Reliability Council of Texas (ERCOT).

Major projects that have been identified and are in the planning-licensing-construction pipeline include the Morgan Creek-Red Creek-Comanche Switch project, which will increase transmission capacity from West Texas to North Texas and improve reliability in the San Angelo area. This project is scheduled to be completed in the summer of 2003. Significant transmission enhancements are also in the pipeline to address reliability issues and enhance competitiveness in the Dallas-Fort Worth area, the Rio Grande Valley, and the area around McCamey, where a number of renewable generation projects have been built.

2. Transmission Constraints Affecting the Deliverability of Wind Generation

Texas is nearly three years ahead of schedule with respect to meeting the Legislature's goal for new renewable generation capacity. Nearly all of this progress is attributable to the installation of wind power in West Texas. However, so much wind power has been added that the existing transmission system is not capable of delivering all of the power than can be generated under peak generating conditions. Wind farms are routinely ordered by ERCOT system operators to curtail output in order to maintain safety and reliability standards and prevent damage to the transmission grid. This problem is currently concentrated in the Rio Pecos/McCamey area.

Several issues combine to cause this problem:

- Construction of new wind plants can occur in a much shorter time than the construction of new transmission facilities;
- Federal production tax credits that have historically been statutorily authorized only for several years at a time. The production tax credit has the effect of making wind generation economically competitive with other sources. As a result, when the expiration of the tax credit nears, there has typically been a rush of new generation built as developers seek to ensure that they will receive the tax credit.
- Under the current ERCOT market structure, wind farms that are instructed by the ERCOT system operator to curtail output are compensated for the power not generated. Additionally, the ERCOT stakeholders have agreed to compensate wind farms for the value of lost tax credits and renewable energy credits (up to a cap of $10 million), both of which normally are only received for actual output. The combination of these payment streams reduces the risk to wind farm developers of locating in a transmission constrained area.

The ultimate solution to insufficient transfer capacity is to build more transmission, and several transmission utilities are constructing new lines and upgrading existing lines to alleviate transmission constraints. However, transmission capacity will still fall substantially short of wind capacity, even with the completion of pending transmission projects. While the Commission has recently revised several rules related to the transmission siting and approval process, the siting, approval, and construction of new transmission additions will remain a lengthy process. Additionally, the costs of installing new transmission will ultimately increase transmission rates to all customers in ERCOT.

The Commission is currently exploring these issues and potential solutions in Project No. 25819, *PUC Proceeding to Address Transmission Constraints Affecting West Texas Wind Power*

Generators, and ERCOT is currently addressing local transmission constraint issues in the Rio Pecos/McCamey area through its Wholesale Market Subcommittee.

F. WHOLESALE PRICE LIQUIDITY AND TRANSPARENCY

The implementation of competition in the wholesale electric market pursuant to PURA 1995 (as well as FERC Open Access requirements) has led to a dramatic increase in wholesale electricity trading. Private price reporting agencies perform surveys of electricity traders and publicly reported average prices. Market participants have developed sufficient confidence in these indices so that many contracts were tied to these prices.

Private entities such as APX, Enron Online, and Intercontinental Exchange (ICE) also developed trading platforms that buyers and sellers used in order to facilitate a broader, more liquid and transparent market. Growth in these exchanges has provided additional transparency to market participants as to the price of electricity in different markets.

Neither private reporting agencies nor exchanges are regulated by the Commodities Futures Trading Commission (CFTC) as a result of an exemption in federal securities regulation for energy trading. The FERC staff recently issued a report questioning the validity of prices reported for both natural gas and energy markets by these private, non-regulated exchanges. In contrast, the FERC staff found that the natural gas markets conducted by the New York Mercantile Exchange (NYMEX) are the most liquid markets in the country, and provide reliable prices as a result of CFTC oversight and regulation of NYMEX, and the extensive audit trail and quality assurance procedures that NYMEX has in place.

Confidence in these private indices and exchanges has been significantly decreased as a result of revelations that market participants provided false information to the reporting firms and engaged in "round-trip" or "wash" trading whereby equal amounts of electricity were traded between buyers and sellers at the same prices. Reporting of such trades artificially increased trading volumes of the participating companies, and artificially increased the revenues reported to securities regulators. Such trades and reporting may have also affected the prices publicly reported by the private indices and exchanges, and may have affected the profits reported by companies using "mark-to-market" accounting. Companies have terminated traders that have reported false price data, restated financial statements to remove the effects of "wash trading", eliminated the use of mark-to-market accounting, and in some cases, exited the energy trading business entirely.

The lack of confidence in private exchanges and indices has lead to a contraction in the reporting to and trading in these markets. Conversely, NYMEX natural gas markets have actually seen an increase in trading, as traders have shifted their business to the more reliable markets conducted by NYMEX. However, because NYMEX is still in the process of developing electricity trading products for ERCOT, REPs and power generators are finding it difficult to appropriately value wholesale electricity products, potentially making the market less efficient.

Additionally, rating agencies have downgraded the credit ratings of the majority of energy industry participants, making it more difficult for these companies to participate in the wholesale market. As a result, trading has declined further as market participants have either scaled back, or eliminated their trading organizations as a way to reduce their collateral requirements, so that available cash and credit may be used for other purposes.

Private reporting agencies and the companies that report trading data to them have begun to respond to these concerns by creating more explicit and rigid standards for reporting data, such as preventing individual traders from reporting prices and instead certifying prices through companies' risk management officers. The energy industry has also begun to develop codes of conduct for participation in wholesale markets and standard trading and netting agreements that reduce the collateral needed to conduct trades.

Several parties have also expressed concerns that affiliated REPs and their affiliated power generation companies in ERCOT have largely contracted with each other in bilateral contracts, thereby limiting the ability of new generation plants to compete to serve retail customers. This problem should decrease over time as the ties between the affiliated REP and PGC diminish as customers switch to alternate suppliers and increased pressures are placed on the affiliated REPs to procure the least expensive power available. The Commission is also addressing this issue through several rulemaking projects related to codes of conduct in the wholesale market and the reporting of bilateral trades, discussed further below.

In approving the ERCOT Protocols, the Commission ordered ERCOT to prepare a report concerning the technical implications of relaxing or eliminating the balanced schedule requirement. The current Protocols require each QSE to submit a day-ahead balanced energy schedule for every 15-minute interval based on the QSE's load forecast for the following day. Stakeholders included the balanced schedule requirement because it would create less credit and financial risk for ERCOT, and potentially provide more operational stability during the transition to a single control area. However, a relaxed balanced schedule in which QSEs can schedule their loads and resources according to market incentives rather than strict adherence to load forecasts could increase liquidity in spot and forward energy markets. ERCOT implemented the relaxed balanced schedule on a trial basis in November 2002.

Additionally, the Commission has opened a rulemaking to explore requiring wholesale market participants to provide information regarding their bilateral contracts, including price and duration of contracts, to the Commission, which would then disclose the data while protecting the confidentiality of individual buyers and sellers. The Commission is also exploring whether elements of the FERC's Standard Market Design should be implemented in ERCOT, in part due to the added transparency and liquidity that those elements might add to the ERCOT market.

The combination of these initiatives and an eventual recovery of the wholesale electricity industry from its current downturn should help improve the liquidity of the wholesale market and increase price transparency in the market. However, the Commission will continue to explore methods and market designs that will aid in the development of a robust and liquid marketplace.

G. FEDERAL LEGISLATION

The United States Senate and the United States House of Representatives both passed legislation relating to the energy industry during the 107th Congress. However, the bills could not be reconciled in conference committee proceedings, and no legislation was ultimately adopted by the Congress. Generally, the Senate version of the bill included many provisions related to electricity restructuring, while the House included far fewer provisions related to electricity issues.

Energy legislation is expected to be considered again in 2003 during the 108th Congress. Several electricity provisions of the House and Senate energy bills that would have an impact on Texas are expected to be reconsidered. Major issues included in one or both bills include:

- **Amendments to the Federal Power Act.** The Senate version of the energy bill would have placed municipal and federal utilities under the jurisdiction of FERC and would have required these utilities to provide open access to their transmission systems. FERC would have also received extended merger authority under the Senate version of the bill, but the bill would have excluded FERC from review of plant sales that are under state jurisdiction. The House version did not have similar provisions.

- **Regional Coordination of Transmission.** The Senate bill would have required the Department of Energy to assist states in coordinating energy policies and infrastructure planning on a regional basis, and to convene an annual conference promoting regional coordination. The House version did not contain similar provisions.

- **Reliability.** The Senate version of the bill would have given FERC explicit authority over reliability organizations, and all users and operators of the bulk power system. FERC would have also been required to establish and enforce mandatory reliability standards, with deference to "interconnection wide" organizations.

- **Public Utility Holding Company Act (PUHCA) Repeal.** PUHCA repeal was included in the Senate bill, eliminating barriers to mergers of utilities, but states and federal authorities would have retained authority to inspect books, records, and accounts of utilities.

- **Public Utility Regulatory Policies Act (PURPA) Amendments.** The mandatory purchase requirements by utilities of power generated by cogenerators and other small power generators would have been repealed by the Senate bill for areas of the county where independently administered day-ahead and real-time markets exist. The Senate bill also contained requirements for states to consider a real-time pricing standard, required the provision of net-metering for on-site renewable generators, required access to the grid by distributed generation resources, and required utilities to develop plans to minimize dependence on single fuels and to increase their efficiency.

- **Renewable Portfolio Standards.** The Senate bill would have required retail electricity suppliers to, beginning in 2005, procure a percentage of their power from renewable resources, excluding existing hydroelectric power, reaching 10% by 2020. Retail suppliers would be permitted to purchase credits at a cost of 1.5 cents per kWh in order to meet their requirement.

- **Tax Incentives and Credits.** The Senate bill would have provided approximately $14 billion in tax incentives and credits, split evenly between production and conservation, including an extension of the current renewable production tax credit until 2013, $1.9 billion for clean coal initiatives, and $2.4 billion for conservation and energy efficiency initiatives. The House bill would have provided $33.5 billion in tax credits and conservation measures, including an extension of the wind and biomass tax credits until 2007, $3.3 billion for clean coal, a $2,000 tax credit for residential solar energy use or energy efficiency improvements, and other energy-efficiency measures.

- **Low-Income Home Energy Assistance Program (LIHEAP) and Weatherization.** Both versions of the bill provide for increase in LIHEAP grants of $3.4 billion, and increased weatherization grants to $325 million in 2003.

VII. LEGISLATIVE RECOMMENDATIONS

The Commission does not recommend any changes or additions to PURA that would alter the fundamental framework for the transition to competition established by the Legislature in SB 7. The Commission does recommend changes to PURA to increase the ability of the Commission to enforce PURA and the market rules developed to implement SB 7. The Commission also recommends a change to the Gas Utility Regulatory Act in order to enhance competition in the electric market, and recommends several changes related to competitive metering and the authority of the Commission to order new transmission construction to alleviate transmission constraints.

A. LEGISLATIVE RECOMMENDATIONS

1. Administrative Penalties Statute

PURA § 15.023 grants authority to the Commission to enforce Commission rules and PURA, and to assess administrative penalties for violations of PURA or Commission rules. Through experience gained in the first year of retail competition, the Commission is concerned that certain provisions in this section may unintentionally impede the ability of the Commission to perform that role.

These include the following:

- The statute currently has a cap on administrative penalties of $5,000 per violation. The Commission is concerned that this cap may not be enough of a deterrent to prevent the exercise of market power or manipulation of market rules that could potentially enrich a company by millions of dollars. The FERC has recently identified a similar concern and requested an increase in its cap on penalties to $25,000 per violation.

- The statute currently appears to mandate referral of enforcement proceedings to the State Office of Administrative Hearings (SOAH). While the Commission relies on, and will continue to rely on the expertise of SOAH in most enforcement proceedings, the Commission is concerned that in some cases (especially in the case of a provider that has declared bankruptcy) there may be insufficient time to refer an action to SOAH. In these cases, a provider may cease to legally exist, or a Federal Bankruptcy Court may set a claims bar date, before SOAH can hear the proceeding, prepare a proposal for decision, and return the matter to the Commission for final action.

- The statute also prohibits the Commission from assessing administrative penalties if a company remedies the violation within 30 days of receiving the notice of intent to assess administrative penalties (except for violations of Chapters 17, 55, or 64 of

PURA[80]). The Commission is concerned that this provision may provide the unintended incentive for companies to violate Commission rules or PURA, knowing that if those violations are discovered by the Commission, they can remedy the violation without penalty. As a result, the statute may deter non-compliance as originally intended. The Commission believes that violations of Chapter 39 of PURA should also be exempted from this requirement.[81]

The Commission recommends the following changes in PURA to address these concerns:

§ 15.023 ADMINISTRATIVE PENALTY

(a) No change

(b) The penalty for violation may be in an amount not to exceed **~~$5000~~** **$25,000.** Each day a violation continues or occurs is a separate violation for purposes of imposing a penalty.

(c) No change

§ 15.024 ADMINISTRATIVE PENALTY ASSESSMENT PROCEDURE

(a)-(b) no change

(c) A penalty may not be assessed under this section if the person against whom the penalty may be assessed remedies the violation before the 31st day after the date the person receives the notice under Subsection (b). A person who claims to have remedied an alleged violation has the burden of proof to the commission that the alleged violation was remedied and was accidental or inadvertent. This subsection does not apply to a violation of Chapter 17, **39,** **~~or~~** 55 or 64.

(d)-(e) no change

(f) If a person requests a hearing or fails to timely respond to the notice, the executive director shall set a hearing and give notice of the hearing to the person. The hearing shall be held **in accordance with Subchapter B of Chapter 14 of this title** **~~by an administrative law judge of the State Office of Administrative Hearings. The~~** **For hearings conducted by the State Office of Administrative Hearings, the** administrative law judge shall make findings of fact and conclusions of law and promptly issue to the commission a proposal for a decision about the occurrence of the violation and the amount of a proposed penalty. Based on the findings of fact, conclusions of law, and proposal for a decision, the commission by order may find that a violation has occurred and impose a penalty or may find that no violation occurred.

(g) No change

2. Gas Utility Regulatory Act

The Commission recommends that the Legislature address implications that electric restructuring may have on Texas's retail natural gas markets. As Texas's competitive electric market becomes more mature, there will be an increasing number of issues in adjacent industries, such as the natural gas industry, that the Legislature should address.

One such issue may be a potentially anti-competitive situation involving affiliated natural gas utilities and REPs.

The largest affiliated REP in Texas is affiliated with one of the largest natural gas local distribution utilities. REPs that have an affiliated gas utility may be in a position to offer combined billing for electric and gas service. It is also possible that the REP may be able to

[80] PURA Chapters 17 and 64 relate to customer protections. Chapter 55 relates to certain regulations of telecommunications services.

[81] PURA Chapter 39 relates to the restructuring of the electric industry.

directly provide gas services by re-branding the gas service under the REP name. In either event, the affiliated REP may have a competitive advantage over other REPs by virtue of being able to offer customers a single bill for both gas and electric service.

Another such issue is whether to open the residential natural gas market to competition. Some states that have implemented retail electricity competition have also implemented retail gas competition. Some providers in those markets have offered both gas and electric services to customers as a way to distinguish themselves in the competitive market. Giving REPs the opportunity to provide an additional product could permit greater savings opportunities for customers and the convenience of paying a single bill. This would also allow REPs the opportunity to spread their customer acquisition, billing, and customer service costs and thereby leverage their resources to broaden their ability to market to new customers.

In some markets, combined electric and gas services have been very popular. In the United Kingdom, for example, the regulator recently reported that 75% of residential customers who switch suppliers switch both gas and electric providers at the same time.[82]

There are several approaches that the Legislature could take in addressing residential natural gas competition. One avenue would be to add a provision to the Gas Utilities Regulatory Act that requires local distribution companies to offer combination billing or re-branding to all REPs on the same terms and conditions that it does for its affiliated REP. This would facilitate an additional means of competition in the electric market without requiring the same degree of unbundling as was required in the electric industry. In order to accomplish this goal, the Legislature would need to amend the Gas Utilities Regulatory Act to permit REPs the opportunity to purchase and resell the gas utilities existing retail natural gas service at an avoided cost discount.[83]

While this method of competition would not provide the full benefits of competitive supply, it would provide an incremental profit opportunity to the REP since the provider has already invested in the systems required to serve and bill the customers. Moreover, the gas utility would likely be indifferent as to whether it supplies at wholesale or retail since it would avoid the incremental retail billing and customer service costs if the REP becomes a wholesale customer.

Another approach would be to require that local distribution companies provide open access over their gas distribution systems. The Gas Utility Regulatory Act already permits industrial and or similar large volume customers the choice to negotiate unbundled distribution rates with a gas utility.[84] If the Legislature believes that the co-marketing of natural gas and electricity would offer smaller customers potential savings and a greater choice of services, then it should clarify that local distribution companies should provide unbundled distribution service to residential and small commercial customers or for resale by other marketers.

---

[82] *Restructuring Today*, December 5, 2002.

[83] The avoided cost discount would recognize that the gas utility would no longer be required to provide billing and customer service function to the retail customer.

[84] Gas Utility Regulatory Act, § 104.003(b).

3. Metering

PURA Section 39.107(a) mandates that metering services for commercial and industrial customers become competitive services beginning January 1, 2004. As discussed in Section III.A.3 of this report, the Commission is currently working towards implementing this provision through a rulemaking proceeding. However, several market participants have voiced concerns about the changes that will need to be made to ERCOT (and other market participants') systems to accommodate competitive metering, especially in the context of the amount of effort that is continuing to be expended to resolve the switching, move-in, and billing problems experienced in the marketplace to date. Given the limited amount of time until 2004 to make and test these changes, the Commission will likely explore a gradual phase-in of competition for these services in order to ensure that additional billing problems do not emerge. The Commission believes that approach is consistent with PURA Section 39.107(a), but believes it would be appropriate for the Legislature to amend 39.107(a) to clarify that a gradual, prudent implementation is appropriate.

PURA § 39.107(b) requires that metering services for residential customers be provided as a regulated service by the TDU until the later of September 1, 2005, or when the affiliated REP loses 40% of its customers to non-affiliated REPs. This provision may unintentionally provide a disincentive for the deployment of newer advanced metering services to residential customers. TDUs may be unwilling to invest a significant amount of capital in advanced metering services if it is unclear as to how long those services will remain regulated. Similarly, it is unclear as to when the affiliated REPs will lose 40% of their residential customers to other REPs, and it is possible that some areas will reach that goal long in advance of others.

The following amendments to PURA would address these concerns:

§ 39.107 METERING AND BILLING SERVICES

(a) On introduction of customer choice in a service area, metering services for the area shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice. Metering services provided to commercial and industrial customers shall be provided on a competitive basis beginning on January 1, 2004**, on a schedule to be determined by the commission**.

(b) Metering services provided to residential customers shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice **unless the commission determines otherwise.** ~~**until the later of September 1, 2005, or the date on which at least 40 percent of those residential customers are taking service from unaffiliated retail electric providers.**~~ Metering and billing services provided to residential customers shall be governed by the customer safeguards adopted by the commission under Section 39.101.

(c)-(g) no change

4. Construction of New Transmission Investment

As discussed in Section VI.E of this report, ERCOT is currently responsible for identifying existing and potential transmission constraints and for providing the Commission with recommendations for meeting the needs of the transmission system. ERCOT staff currently performs this analysis with the assistance of TDUs, and leads three regional working groups to identify areas where upgrades to the transmission grid are needed.

PURA § 39.203(e) allows the Commission to order the construction (or enlargement) of transmission or distribution facilities in order to ensure safe and reliable service for the state's electric markets. PURA § 39.157(a) also permits the Commission to order the construction of new facilities in order to remedy the exercise of market power. However, the Commission does not have clear authority to order the construction of new transmission if a safety, reliability, or market power situation does not exist. Inadequate transmission facilities have the effect of potentially increasing costs to generators and customers (through congestion costs and the need for ERCOT to enter into reliability must-run contracts) although it is the TDUs that can alleviate transmission congestion through the construction of new facilities.

The Commission believes that it would be appropriate for the Legislature to clarify the Commission's authority to order the construction of new transmission or distribution facilities in order to enhance the efficient operation of the competitive electric market, if infrastructure addition is the most cost effective method of solving market problems. The following amendment to PURA would accomplish this goal:

§ 39.203. TRANSMISSION AND DISTRIBUTION SERVICE

(a)-(d) no change
(e) The commission may require an electric utility or a transmission and distribution utility to construct or enlarge facilities to ensure safe and reliable service for the state's electric markets, **<u>or to reduce transmission congestion.</u>** In any proceeding brought under Chapter 37, an electric utility or transmission and distribution utility ordered to construct or enlarge facilities under this subchapter need not prove that the construction ordered is necessary for the service, accommodation, convenience, or safety of the public and need not address the factors listed in Sections 37.056(c)(1)-(3) and (4)(E).
(e)-(h) no change

B. CLARIFICATIONS

As with any legislation of the magnitude of SB 7, there are a number of ambiguities that have come to light during its implementation. For the most part, the Commission has addressed these issues through the adoption of rules or by way of decisions in contested proceedings. If the Legislature concludes that electric restructuring issues should be reconsidered, there are several areas where it may be appropriate to clarify PURA and SB 7.

1. System Benefit Fund

During the 77th Legislature, changes were made to PURA § 39.903, relating to System Benefit Fund (SBF). HB 3088, HB 1902, and HB 2156 created two subsections (a), each with a separate purpose, and two subsections (e), each with a separate list of funding priorities. Section 21(a) of HB 3088 specified that HB 3088 controlled over all other Acts of the 77th Legislature. The Commission believes it is appropriate to clarify PURA § 39.903 in order to eliminate any confusion about the nature of the fund and the priorities for expenditures from the fund.

HB 3088 restored the original trust fund status of the SBF, and the Comptroller has established the fund as a trust fund. Even though HB 1902 retained the original language of PURA § 39.903(a), and referred to the fund as a general revenue fund, HB 3088 controls over this provision, as discussed above. HB 1902 also specified that interest on the fund was to be credited to the fund, and since HB 1902 did not conflict with HB 3088, the Comptroller is retaining interest earned on the fund, in the fund. The proposed amendment to PURA § 39.903(a) below is consistent with the Comptroller's current treatment of the fund, and would clarify this portion of the statute.

HB 3088 and HB 2156 also provided that the fund be used solely to support certain regulatory purposes. HB 1902 contained similar provisions, but additionally provided for a prioritization of the various purposes. The Commission believes that the program allocations of the SBF are appropriately set according to the priorities listed in Subsection (e) of HB 1902. The Commission believes that HB 1902 appropriately established the fund priorities and recommends repealing PURA §39.903(e) as enacted by HB 3088 and HB 2156.

The following amendments to PURA would accomplish these clarifications:

§ 39.903. SYSTEM BENEFIT FUND. ~~**(As amended by HB 1902)**~~

~~**(a) The system benefit fund is an account in the general revenue fund that may be appropriated only for the purposes provided by this section. Interest earned on the system benefit fund shall be credited to the fund.**~~

~~**(As amended by HB 3088):**~~

(a) The system benefit fund is created as a trust fund with the comptroller in the state treasury. **<u>Interest earned on the system benefit fund shall be credited to the fund.</u>**

(b) The system benefit fund is financed by a nonbypassable fee set by the commission in an amount not to exceed 65 cents per megawatt hour. The system benefit fund fee is allocated to customers based on the amount of kilowatt hours used.

(c) The nonbypassable fee may not be imposed on the retail electric customers of a municipally owned utility or electric cooperative before the sixth month preceding the date on which the utility or cooperative implements customer choice. Money distributed from the system benefit fund to a municipally owned utility or an electric cooperative shall be proportional to the nonbypassable fee paid by the municipally owned utility or the electric cooperative, subject to the reimbursement provided by Subsection (i). On request by a municipally owned utility or electric cooperative, the commission shall reduce the nonbypassable fee imposed on retail electric customers served by the municipally owned utility or electric cooperative by an amount equal to the amount provided by the municipally owned utility or electric cooperative or its ratepayers for local low-income programs and local programs that educate customers about the retail electric market in a neutral and nonpromotional manner.

(d) The commission shall annually review and approve system benefit fund accounts, projected revenue requirements, and proposed nonbypassable fees. The commission shall report to the electric utility restructuring legislative oversight committee if the system benefit fund fee is insufficient to fund the purposes set forth in Subsection (e) to the extent required by this section.

(e) The system benefit fund shall provide funding solely for the following regulatory purposes and in the following order of priority:

(1) programs to assist low-income electric customers by providing the 10 percent reduced rate prescribed by Subsection (h);

(2) customer education programs, administrative expenses incurred by the commission in implementing and administering this chapter, and expenses incurred by the office under this chapter;

(3) programs to assist low-income electric customers by providing the targeted energy efficiency programs described by Subsection (f)(2);

(4) the school funding loss mechanism provided by Section 39.901; and

(5) programs to assist low-income electric customers by providing the 20 percent reduced rate prescribed by Subsection (h).

~~**(As amended by HB 2156 and 3088):**~~

~~**(e) Money in the system benefit fund may be appropriated to provide funding solely for the following regulatory purposes:**~~

~~**(1) programs to assist low-income electric customers provided by Subsections (f)-(l);**~~

~~**(2) customer education programs;**~~

~~**(3) the school funding loss mechanism provided by Section 39.901; and**~~

~~**(4) reimbursement to the commission and the Texas Department of Human Services for expenses incurred in the implementation and administration of an integrated eligibility process created under Section 17.007 for customer service discounts relating to retail electric service, including outreach expenses the commission determines are reasonable and necessary.**~~

(f)-(l) no change.

2. Performance-Based Ratemaking

Performance-based ratemaking is a method of establishing rates which departs, in part, from the normal cost-of-service standard in setting just and reasonable utility rates. Performance-based rates generally afford utilities opportunities to increase their profits by exceeding targets for efficiency and cost savings, and penalizes utilities for not meeting those targets. This type of methodology may streamline the regulatory process by replacing rate hearings with annual accounting-type reviews of performance and earnings, as well as provide added incentives for the addition of needed transmission facilities or superior performance with retail related transaction processing.

In past proceedings, some parties have argued that the Commission lacks authority to implement performance-based ratemaking or that the Commission's authority to do so is very limited. It would be expedient to avoid such controversy in the future and to minimize the possibility of unnecessary litigation over the Commission's authority by including in PURA an explicit grant of authority to the Commission to use performance-based ratemaking. This objective could be achieved with the following changes:

§ 36.051. ESTABLISHING OVERALL REVENUES

(a) In establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable rate of return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses.

(b) The commission may set performance-based rates and may adjust the overall revenues of a utility to reflect the quality of the utility's service and/or to encourage needed transmission and distribution infrastructure investments and expansion or other goals. To implement performance-based rates, the commission may use any reasonable means including establishing a system of revenue adjustments that are made automatically, without the need for a further commission proceeding, based on pre-established performance measures. The performance measures shall be established by the commission prior to the period in which performance will be evaluated for purpose of adjusting revenue.

3. Recovery of Rate Proceeding Expenses by Municipalities

PURA § 33.023 requires electric utilities to reimburse municipalities for reasonable expenses of participating in ratemaking proceedings. In the first set of price-to-beat fuel factor adjustment proceedings, several cities intervened and participated in the cases and requested reimbursement from the affiliated REPs. The Commission found that because PURA

§ 31.002(6)(H) excludes retail electric providers from the definition of electric utility, the affiliated REPs were not required to reimburse cities for their expenses for participating in the rate proceedings.

If the Legislature's intent was that cities should continue to be reimbursed for expenses incurred in participating in rate proceedings involving the price-to-beat rates of the affiliated REPs, the Commission recommends amending PURA as follows:

§ 33.023 RATEMAKING PROCEEDINGS

(a) The governing body of a municipality participating in or conducting a ratemaking proceeding may engage rate consultants, accountants, auditors, attorneys, and engineers to:

(1) conduct investigations, present evidence, and advise and represent the governing body; and

(2) assist the governing body with litigation in an electric utility ratemaking proceeding before the governing body, a regulatory authority, or a court.

(b) The electric utility **or affiliated retail electric provider** shall reimburse the governing body of the municipality for the reasonable cost of the services of a person engaged under Subsection (a) to the extent the applicable regulatory authority determines is reasonable.

4. Abuses in the Wholesale Electric Markets

The investigation of events in the California energy crisis and the collapse of Enron have revealed a number of practices by wholesale energy producers and traders that have been detrimental to the fair and efficient operation of the wholesale electric markets. These practices were typically intended to permit energy companies to maximize their profits, at the expense of trading partners or retail customers.

There are a number of practices or allegations that have received the attention of trading partners, the market monitoring units in other regions of the country, the FERC, representatives of retail customers, and the press:

- Power producers in California withheld production from the market to drive up prices;
- Power producers and traders in California intentionally created congestion on the transmission system, in order to get paid for relieving the congestion;
- Power producers and traders in California misrepresented the status of their power transactions to make it appear that there was congestion on the transmission system, in order to get paid for relieving the congestion;
- Power producers and traders engaged in wash trades in many regions of the country to inflate reported trading volume and revenues, which may also have resulted in inflated perceptions of market prices;
- Power traders misrepresented prices or volumes of trade in reporting power trades to publications that report prices and volumes, which may have resulted in inflated price indices; and
- Power schedulers in ERCOT may have misrepresented their customers' demand when they knew that the transmission system was likely to be congested, in order to take advantage of the price differentials that exist when the system is congested.

Many of these practices are possible because electricity cannot be stored economically and can only be transported within the limits of the transmission system. Supply and demand must be equalized in an electrical system, within very small tolerances. In the markets for most other commodities, sellers have more ability to use transportation and storage to meet customers' needs, and buyers have the time to consider the price of a commodity and decide to defer a purchase or not buy at all. In wholesale electric markets, supply and demand must match, and supply shortages at a particular place and time can result in high prices. For this reason, market power can arise in many locations and at many times. As producers recognize the circumstances in which these shortages might result, they can adopt strategies to take advantage of the shortages, or create shortages and then take advantage of them.

There appears to be a continuum of conduct in the market that at one extreme may be considered legitimate, profit-maximizing conduct but at the other extreme constitutes fraud. One of the difficulties is that the middle of the continuum is not well charted. Different people have different perspectives on some of the strategies that power producers or traders use to maximize their profits. The FERC is struggling with this issue in adjudicating the claims for refunds or damages that buyers of power in California have filed against sellers. The Commission has also dealt with this issue in connection with the issue of over-scheduling of demand in August 2001. While the Texas market, which is primarily a bilateral market, is less subject to market abuses than the original California market, there is a potential for abuses to occur. When they occur, wholesale buyers of power and entities that operate in the ERCOT market may be exposed to high costs, without means to insulate themselves from these costs. The abuses that have occurred in markets since SB 7 was enacted emphasize the importance of vigorous market monitoring and providing the organization that is responsible for the monitoring with the tools it needs to do the job.

As discussed in Section IV.A.1, the Commission has already addressed the issue of wholesale market behavior that has a detrimental effect on the market with respect to issues surrounding overscheduling. That issue was addressed prospectively through changes in the market rules governing the allocation of congestion costs, and retroactively through a settlement that provided refunds to market participants harmed by overscheduling.

The Commission is also currently addressing the prevention of market abuses through the establishment of a code of conduct for wholesale market participants, either within the ERCOT Protocols, or by rule of the Commission. While the Commission has found that it does have the authority to either require ERCOT to develop a code of conduct for market participants, or to establish such a code of conduct itself, several parties have asserted that the Commission does not have the authority to do so. As such, it may be likely that efforts of the Commission to remedy abuses in the wholesale market may be hampered by lengthy, costly, and unnecessary litigation over the Commission's authority.

The Commission believes that it would be appropriate for the Legislature to consider amendments to PURA § 39.157 to:

- Clarify that the Commission has clear authority to remedy all abuses of market power, irrespective of the specific times and places it occurs, and irrespective of the ownership and control of generation in a power region;

- Clarify that the Commission has clear authority to define what conduct in the wholesale market is improper; and
- Clarify that the Commission has clear authority to order refunds to the persons harmed by improper wholesale market behavior.

Additionally, the Commission believes that it would be appropriate for the Legislature to consider amendments to PURA § 39.151 to clarify that the Commission has clear authority to enforce the ERCOT Protocols over all wholesale market participants, including the authority to require refunds to the persons harmed by non-compliance with the ERCOT Protocols.

5. Credit Scoring

Credit scoring may have a negative impact on certain customers participating in electric competition.[85] It appears that some applications of credit scoring may result in the inappropriate denial of service or the inappropriate assessing of higher rate offerings to customers. While the Commission anticipates addressing this issue in its pending project to re-evaluate the Commission's customer protection rules, the Legislature may want to clarify whether credit scoring in general, or certain applications of credit scoring, violates the anti-discrimination provisions of PURA § 17.004(a)(4).

[85] A credit score is the calculated result of a mathematical equation that incorporates many types of information found in a person's credit report. The score is intended to be an indicator of future credit risk.

Appendix 1

ACRONYMS

AEI – Automated Energy, Inc.
AEP – American Electric Power
APA – Administrative Procedures Act (state)
AREP – Affiliated retail electric provider
BENA – Balancing energy neutrality adjustment
CCN – Certificate of convenience and necessity
CBO – Community-based organization
CDR – Capacity-demand-reserve
CEO – Chief Executive Officer
CFTC – Commodity Futures Trading Commission
CIO – Chief Information Officer
CMO – Chief of Market Operations
COO – Chief Operations Officer
CPL – Central Power and Light
CRPP – The Center for Research & Public Policy
CTC – Competition transition charge
DHS – Texas Department of Human Services
ECOM – Excess cost over market model
EES – Enron Energy Services, Inc.
EGSI – Entergy Gulf States, Inc.
EIA – Energy Information Agency of the U.S. Department of Energy
EMC – Excess mitigation credit
EPMI – Enron Power Marketing, Inc.
ERCOT – Electric Reliability Council of Texas
ESI ID – Electronic service identifier
FERC – Federal Energy Regulatory Commission
HL&P – Reliant HL&P, formerly Houston Lighting and Power
IOU – Investor-owned utility
ISO – Independent system operator, also referred to as independent organization
IPP – Independent power producer
KW - Kilowatt
KWh – Kilowatt-hour
LCRA – Lower Colorado River Authority
LIDA – Low income discount administrator
LIHEAP –Low income home energy assistance program
LITE-UP – Low Income Telephone and Electricity Utilities Program
LMP – Locational marginal pricing model
M&B – Metering and billing
MMBtu – million British thermal units
MOD – Market Oversight Division of the Public Utility Commission of Texas
MOU - Municipally owned utility
MW - Megawatt
MWh – Megawatt-hour
NOPR – Notice of Proposed Rulemaking

Appendix 1

NYMEX – New York Mercantile Exchange
OATT – Open access transmission tariff
OPUC – Office of the Public Utility Counsel
PGC – Power generation company
PIWG – Pilot Implementation Working Group
PMEI – Pulse metering equipment installation
POLR – Provider of Last Resort
PRR – Protocol revision request
PRS – Protocol Revisions Subcommittee of ERCOT
PSA – Public service announcement
PTB – Price to Beat
PTB REP – A retail electric provider required to serve customers at the price to beat
PTC – production tax credit (a federal tax credit to renewable energy producers)
PUC, PUCT – the Public Utility Commission of Texas
PUHCA – Public Utility Holding Company Act (federal)
PURA – Public Utility Regulatory Act (state)
PURPA – Public Utility Regulatory Policies Act (federal)
QF – Qualifying facility
QRE – Quick recovery effort
QSE – Qualified scheduling entity
REP – Retail electric provider
RFP – Request for proposals
RMS – Retail Market Subcommittee of ERCOT
ROS – Reliability and Operations Subcommittee of ERCOT
RTO – Regional transmission organization
SB 7 – Senate Bill 7
SBF – System Benefit Fund
SECO – State Energy Conservation Office
SESCO, TXU-SESCO – formerly Southwestern Electric Service Company, now a division of TXU Energy Co.
SMD – Standard market design
SOAH – State Office of Administrative Hearings
SPP – Southwest Power Pool
SPS – Southwestern Public Service Company
SWEPCO – Southwestern Electric Power Company
TAC – Technical Advisory Committee of ERCOT
TCR – Transmission congestion rights
TCRF – Transmission cost recovery factor
TDBU – Transmission and distribution business unit
TDHCA – Texas Department of Housing and Community Affairs
TDSP – Transmission and distribution service provider
TDU – Transmission and distribution utility
TNMP – Texas-New Mexico Power Co.
TXU – TXU Electric Co. (formerly Texas Utilities)
UCOS – Unbundled cost of service
WMS – Wholesale market subcommittee of ERCOT
WTU – West Texas Utilities Co.

Appendix 1

GLOSSARY

Affiliate – a. An entity who directly or indirectly owns or holds at least five percent of the voting securities of another entity; or

b. An entity in a chain of successive ownership of at least five percent of the voting securities of another entity; or

c. An entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by another entity; or

d. An entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by an entity who directly or indirectly owns or controls at least five percent of the voting securities of another entity or an entity in a chain of successive ownership of at least five percent of the voting securities of another entity; or

e. A person who is an officer or director of another entity or of a corporation in a chain of successive ownership of at least five percent of the voting securities of an entity; or

f. An entity that actually exercises substantial influence or control over the policies and actions of another entity; or

g. Any other entity determined by the PUC to be an affiliate;

Aggregator – an entity, registered with the PUC, which aggregates multiple customers for the purpose of negotiating or contracting electricity rates with a REP.

Ancillary Services – electricity purchased by ERCOT for the purpose of guaranteeing transmission of the correct amount of power is available to cover all demand during all periods.

Balancing Energy – energy purchased by ERCOT to maintain a stable voltage level and to make up differences between scheduled and actual demand for energy.

Balancing energy neutrality adjustment – charges by ERCOT to market participants which cover the costs of congestion.

Base Rate – that part of a regulated retail electric tariff which covers all costs of delivering energy other than fuel for generation.

Bilateral market – a market where buyers and sellers negotiate contracts with each other for the delivery of energy on terms chosen by those buyers and sellers.

British thermal unit – a measure of thermal energy equal to the energy needed to raise one pound of water one degree from 39 degrees Fahrenheit, often used as a measure of natural gas.

Appendix 1

Capacity – the ability and readiness of a generation facility to produce power at a given time. The total power generation capability available at a given time for a generation facility, region, or company.

Capacity auctions – a market under which affiliated Power generation companies are required to sell at least 15 percent of their capacity.

Certificate of convenience and necessity – a certificate issued by the PUC which approves a new service area for a utility, the construction of new transmission lines, or other regulated expansion or construction.

Certificated utility – a utility which has received a certificate of convenience and necessity to operate in a specific geographic region.

Commercially significant constraint – a transmission line likely to incur significant repeated costs of mitigating congestion. Used to designate zones in the ERCOT zonal model.

Congestion revenue rights – a financial instrument allowing the holder to obtain a fixed price for transmission regardless of congestion.

Cooperative (Co-op) – a utility established to deliver energy to its owners, generally all residents and businesses in a geographic area.

Direct Assignment – the process by which costs (e.g. of congestion) are charged to the entity or function which caused them to be incurred.

Distributed generation – the production of electricity on the site of end use, especially at small office buildings, hospitals, homes, and small businesses.

Electric Service Identifier (ESI ID) – a code in the ERCOT system assigned to each metered address in the grid, sometimes pronounced "easy ID."

Fuel Factor – that portion of regulated electric tariffs which pay for the cost of fuel in the generation process.

Fuel Surcharge – an additional charge imposed to make up past differences between fuel factor and the actual cost of fuel in a regulated utility rate.

Headroom – the difference between the price to beat and costs incurred by competitive REPs that allow them to enter the market and serve customers profitably.

Independent System Operator (ISO)– an entity created to ensure equal access to transmission and distribution systems, ensure reliability of the electrical network, and ensure that customer's choice of REP is conveyed in a timely manner. ERCOT is the ISO for most of Texas.

Interruptible service – a contract to deliver energy to a retail customer which may be temporarily stopped when certain conditions (e.g., price of power or high load) are met.

Investor-owned utility (IOU)– a for-profit electric utility operated with the intent of delivering profits to stockholders, who may or may not be customers of the utility.

Firm service – a contract to deliver energy to a retail customer regardless of the cost of acquisition to the REP.

Large non-residential customer – an end user with peak demand of more than one megawatt.

LITE-UP Texas – a program which provides a 17% discount on electricity rates to qualifying low-income residents.

Load profiling – the process by which non-pulse metered customers have their usage settled based on an assumed usage profile. This profile is created based on weather and known profile types on a daily basis.

Locational marginal pricing (LMP) – a process by which congestion and power transmission costs being handled on a line-by-line basis.

Megawatt (MW) – a measure of power, one million watts or one thousand kilowatts.

Megawatt-hour (MWh)– the energy required to fulfill one megawatt of demand for one hour.

Market power mitigation plan — A written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by the Public Utility Regulatory Act §39.154.

Municipally-owned utility (MOU) – a utility owned by and run by a city, for the purpose of delivering energy to the residents of that city.

Non-bypassable charges – regulated tariffs covering transmission and distribution costs, the System Benefit Fund, and certain transition related charges and credits which must be passed through to all customers, regardless of competitive status.

Performance-based ratemaking – an alternative form of rate setting which allows utilities to earn profits above regulated levels by exceeding efficiency and cost-cutting targets.

Appendix 1

Pilot Project – the limited initiation of restructuring during the period of June 1, 2001 to December 31, 2001, for the purpose of testing and improving the market restructuring which began January 1, 2002.

Power generation company (PGC) – a firm which owns and operates generating capacity with the intent of selling power into the market.

Power marketer – an entity which purchases and sells electric power.

Price to Beat – the bundled rate an affiliated retail electric provider is required to charge for electricity service in its home territory for residential and small commercial customers. Affiliated REPs are required to offer service at only the price to beat until 36 months after the beginning of competition, or 40% of the residential or small commercial load in that area is served by competitive REPs.

Primary Voltage Level – the level of voltage used to transfer electricity within the grid, delivered to an end user.

Provider of Last Resort (POLR) – a designated REP required under PURA § 39.106 to provide a standard retail electric service package to any requesting customer in its territory. It is chosen under P.U.C. SUBST. R. 25.43 by auction, or by lottery in the absence of bids, with rates approved by the Commission.

Pulse metering – the metering of electricity where power usage is monitored and recorded, along with energy usage.

Redispatching – the reduction of generation by one generating facility by ERCOT order coupled with an increase in generation by another, for the purpose of mitigating congestion.

Reliability must-run contract – a contract between ERCOT and a generation facility deemed to be necessary to maintain the reliability of the network.

Restructuring – the process of introducing competition into the electricity market.

Retail Clawback – the payment of the difference between price to beat and the market price for electricity from the affiliated REP to the affiliated TDU as part of the 2004 true-up proceeding pursuant to PURA § 39.262(e).

Qualified scheduling entity (QSE) – an entity licensed by ERCOT to schedule power for the ERCOT region.

Qualifying facility (QF) – an end user which generates its own power and has the right under law to sell excess power into the grid at avoided cost.

Appendix 1

Renewable energy – any source of energy which can be replenished, such as wind, solar, hydroelectric, and landfill natural gas.

Reserve Margin – the difference between total ERCOT-wide electricity generation capacity and peak demand for electricity.

Retail Electric Provider (REP) – a firm that provides billing and electric service to an end user.

Secondary Voltage Level – any level of electricity voltage delivered by the grid to an end user; other than the standard voltage used to transfer electricity within the grid.

Securitization – a process by which electric utilities recoup stranded costs in a lump sum payment through the issuance of low-interest bonds.

Slamming – the illegal switching of a utility customer from one REP to another without the customer's consent.

Small non-residential customer – a non-residential end user of electricity with peak demand of less than one megawatt.

Standard Market Design (SMD) – an initiative by FERC to establish a consistent set of market rules in the electric industry across the U.S.

Stranded costs – costs incurred in good faith by utilities or power generation companies under regulation that may not be recouped under a competitive market.

Switchable generation – a generation facility that can be used to produce power for areas either within or outside ERCOT.

System benefit fund (SBF) – An account with the Comptroller's Office to be administered by the Commission for the purpose of rate reduction and energy efficiency programs in the low income community.

Transmission constraints – the limitation of power transmission to the capacity of existing lines.

Transmission and Distribution utility (TDU) – the utility that owns transmission and distribution facilities in a certain region.

True-up – the final accounting of stranded costs and accrued mitigation charges meant to allow formerly regulated utilities to recoup costs incurred in good faith under regulation.

Unbundling – the process by which incumbent IOUs were broken into separate power generation, transmission and distribution, and retail electric provider entities.

Appendix 1

Unbundling Cost of Service (UCOS) – the process used to set transmission and distribution tariffs separate from retail and generation prices during the unbundling process.

Wash Trading – establishing contracts both buying and selling power simultaneously, to inflate apparent market share, revenues, or trading volumes in the energy market.

Zonal congestion pricing – a process by which congestion is charged based on identified bottlenecks, where congestion within that zone is considered small and commercially insignificant.

Appendix 2

PUC Rulemaking Proceedings

<u>Adopted Rules—Major Rules</u>

1. Project No. 20936, Code of Conduct for Electric Utilities and Affiliates to implement PURA, § 39.157. Adoption: November 1999.
2. Project No. 20944, Renewable Energy Mandate to implement PURA § 39.904. Adoption: December 1999.
3. Project No. 21066, ERCOT Independent Organization Funding PURA, § 39.151. Adoption: September 1999.
4. Project No. 21072, Goals for Natural Gas Generating Capacity to implement PURA, § 39.9044. Adoption December 1999.
5. Project No. 21073, Electric Service for Public Retail Customers (GLO Access) to implement PURA §§ 40.003, 41.003. Adoption: September 1999.
6. Project No. 21074, Energy Efficiency Programs to implement PURA, § 39.905. Adoption: February 2000.
7. Project No. 21076, Electric Reliability Standards to implement PURA, § 38.005. Adoption: December 1999.
8. Project No. 21080, Terms and Conditions for Transmission Service, including Tariffs and Modifications to Existing Transmission Rules to implement PURA § 35.004. Adoption: December 1999.
9. Project No. 21081, Market Power Mitigation Plans and Generating Capacity Reports to implement PURA §§ 39.155, 39.156, and 39.157. Adoption: August 2000.
10. Project No. 21082, Certification of Retail Electric Providers and Registration of Power Generation Companies and Aggregators to implement PURA Chapter 39, Subchapter H. Adoption: July 2000.
11. Project No. 21083, Cost Unbundling and Separation of Business Activities, Including Separation of Competitive Energy Services, and Distributed Services to implement PURA §§ 39.051, 39.201. Adoption: December 1999.
12. Project No. 21220, Rules for Interconnecting Distributed Generation to implement PURA, § 39.101. Adoption: November 1999.
13. Project No. 21407, Retail Competition Pilot Project to implement PURA § 39.104. Adoption: August 2000.
14. Project No. 22255, Customer Protection Rules to implement PURA §§ 17.004, 39.101. Adoption: December 2000.
15. Project No. 22187, Terms and Conditions for Transmission and Distribution Utilities' Retail Distribution Service to implement PURA § 39.203. Adoption: December 2000.
16. Project No. 21405, Capacity Auction to implement PURA § 39.153. Adoption: December 2000.
17. Project No. 21406, Standards for Recognition of Costs of Environmental Cleanup or Plant Retirement to implement PURA § 39.263. Adoption August 2000.
18. Project Nos. 21187 and 22429, System Benefit Fund Administration, Low-Income Customers to implement PURA § 39.903. Adoption: December 2000.
19. Project No. 21408, Provider of Last Resort to implement PURA § 39.106. Adoption: October 2000.
20. Project No. 21409, Price to Beat to implement PURA § 39.202. Adoption: February 2001.

Appendix 2

21. Project No. 22361, Code of Conduct for Municipal Utilities and Electric Cooperatives to implement PURA § 39.157. Adoption: March 2001.
22. Project No. 22816, Standards for Labeling Electricity with Respect to Fuel Mix and Air Emissions to implement PURA § 39.101. Adoption: August 2001.
23. Project No. 23571, Rulemaking Concerning True-Up Proceeding to implement PURA §39.262. Adoption: November 2001.
24. Project No. 25963, Rulemaking to Establish Guidelines and Standards for Municipal Registration of REPs to implement PURA § 39.358. Adoption: December 2002.

Adopted Rules—Revisions of Major Rules

1. Project No. 24492, Rulemaking Proceeding To Revise Substantive Rule 25.381, Capacity Auctions. Adoption: June 2002.
2. Project No. 25360, Rulemaking Proceeding to Amend Requirements for Provider of Last Resort Service. Adoption: August 2002.
3. Project No. 25610, Rulemaking to Amend Chapter 25, Subchapter H, Div. 2, Regarding Energy Efficiency and Customer-Owned Resources to implement PURA § 39.905. Adoption: September 2002.

Proposed Rules—Major Rules

1. Project No. 24255, Rulemaking Concerning Planning Reserve Margin Requirements to implement various sections of PURA. Target adoption: Second Quarter 2003.
2. Project No. 24462, Rulemaking to Establish Performance Measures Relating to the Competitive Retail Electric Market to implement various sections of PURA. Target adoption: January 2003.
3. Project No. 25959, Rulemaking on Oversight of Independent Organizations in the Competitive Electric Market to implement PURA §39.151. Target adoption: January 2003.
4. Project No. 26188, Rulemaking to Establish Disclosure of Information Related to Electricity Transactions Originating or Terminating in Texas to implement various sections of PURA. Target adoption: Fourth Quarter 2003.
5. Project No. 26201, Rulemaking on Code of Conduct for Wholesale Market Participants to implement various sections of PURA. Target adoption: Fourth Quarter 2003.
6. Project No. 26359, Rulemaking to Address Competitive Metering to implement to implement PURA §39.107(a). Target adoption: Second Quarter 2003.
7. Project No. 26376, Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas to implement PURA §39.151. Target adoption: Fourth Quarter 2003.

Appendix 2

Proposed Rules—Revisions to Major Rules

1. Project No. 24899, Rulemaking Proceeding to Amend P.U.C. Subst. R. 25.451, 25.453, and 25.454, Relating to HB2156 and HB3088 to implement PURA § 39.903. Target adoption: Second Quarter 2003.

2. Project No. 26418, Rulemaking to Address Competitive Energy Services to implement PURA §39.051(a). Target adoption: Second Quarter 2003.

3. Project No. 26556, Revisions to the Provisions of PUC Subst. R. 25.41 Relating to the Price to Beat Fuel Factors. Target adoption: January 2003.

4. Project No. 26848, Rulemaking Proceeding to Amend Subst. R. 25.173, Goal for Renewable Energy. Target adoption: January 2003.

Adopted Rules—Other Rules

1. Project No. 21023, Repeal of Integrated Resource Planning Rules to implement repeal of PURA, Chapter 34

2. Project No. 21046, Form for Securitization of Stranded Costs of Investor-Owned Utilities to implement PURA, § 39.201

3. Project No. 21077, Securitization of Stranded Costs for River Authorities and Coops to implement PURA §§ 40.003, 41.003

4. Project No. 21232, Rule Changes to Conform to Electric Restructuring Act to implement various sections of PURA

5. Project No. 21075, Form for Annual Report of Revenues and Expenses to implement PURA § 39.257.

6. Project No. 21232, Conforming rules to implement various sections of PURA.

7. Project No. 22167, Rulemaking to Establish Procedures for Electric Utilities' Annual Reporting of Workforce Diversity to implement PURA § 39.909(c).

8. Project No. 22540, Rulemaking Proceeding to Amend Existing Rules §25.211 and 25.212 to implement PURA § 39.101.

9. Project No. 23157, Rulemaking Proceeding to Revise PUC Transmission Rules Consistent with the New ERCOT Market Design to implement various sections of PURA.

10. Project No. 23952, Rulemaking Concerning Rulemaking Concerning Pulse Metering to implement various sections of PURA.

11. Project No. 24365, Rulemaking Concerning Arrangements Between Qualifying Facilities and Electric Utilities to implement various sections of PURA.

12. Project No. 24551, Rulemaking to Amend § 25.474 Regarding Initial Retail Electric Provider Selection Process to implement various sections of PURA.

13. Project No. 25515, Electric Utility CCN Rulemaking and Forms Changes to implement various sections of PURA.

14. Project No. 25516, Load Profiling and Load Research Rulemaking to implement various sections of PURA.

Appendix 3

Landowners and Transmission Line Cases at the PUC

Public Utility Commission of Texas

1701 N. Congress Avenue
P.O. Box 13326
Austin, Texas 78711-3326
(512) 936-7261
www.puc.state.tx.us

Effective: January 1, 2003

Appendix 3

PURPOSE OF THIS BROCHURE

This brochure is intended to provide landowners with information about proposed new transmission lines and the Public Utility Commission's process for evaluating these proposals. At the end of the brochure is a list of sources for additional information.

The following topics are covered:
- How the Public Utility Commission (PUC) evaluates whether a new transmission line should be built,
- How you can participate in the PUC's evaluation of a line, and
- How utilities acquire the right to build a transmission line on private property.

You are receiving the enclosed formal notice because one or more of the routes for a proposed transmission line may require an easement or other property interest across your property, or the centerline of the proposed project may come within 300 feet of a house or other habitable structure on your property. (This distance is expanded to 500 feet if the proposed line is greater than 230kVv or greater voltage.) For this reason, your property is considered **directly affected land.** This brochure is being included as part of the formal notice process.

If you have questions about the proposed routes for a transmission line, you may contact the utility company to obtain a more detailed map of the proposed routes for the transmission line and nearby habitable structures.

The PUC is sensitive to the impact that transmission lines have on private property. At the same time, transmission lines deliver electricity to millions of homes and businesses in Texas, and new lines are sometimes needed so that customers can obtain reliable, economical power.

The PUC's job is to assess the utility's proposal and the positions of the parties, and to decide whether a proposed transmission line should be approved. The PUC values input from landowners and encourages you to participate in this process.

PUC TRANSMISSION LINE PROCEEDING

Texas law provides that most utilities must file an application with the PUC to obtain a Certificate of Convenience and Necessity (CCN) in order to build a new transmission line in Texas.
The law requires the PUC to consider a number of factors in deciding whether to approve a proposed new transmission line.

The PUC may grant a CCN after considering the following factors:
- Adequacy of existing service;
- Need for additional service;
- Effect of granting the certificate on the local utility and any utility serving the proximate area;
- Whether the route utilizes existing compatible rights-of-way, including the use of vacant positions on existing multiple-circuit transmission lines;
- Whether the route parallels existing compatible rights-of-way;
- Whether the route parallels property lines or other natural or cultural features;
- Whether the route conforms with the policy of prudent avoidance (which is defined as the limiting of exposures and magnetic fields that can be avoided with reasonable investments of money and effort); and
- Other factors such as community values, recreational and park areas, historical and aesthetic values, environmental integrity, and the probable improvement of service or lowering of cost to consumers in the area.

If the PUC deems a line should be approved, it will grant the utility's application to construct the transmission line.

Utility Application for CCN:
A utility's application for approval of a CCN describes the proposed line and includes a statement from the utility describing the need for the line and the impact of building it. The application also includes a route designated by the utility as a "preferred route"; however, any of the proposed routes may be selected by the Commission.

The PUC conducts a proceeding to evaluate the need and impact of the proposed line and to decide whether to approve it. Landowners who would be affected by a new line can participate in the case in the following ways:
- informally, by filing a protest, or
- formally, by intervening in the PUC proceeding.

Appendix 3

Filing a Protest (informal comments):
If you do not wish to intervene in a CCN proceeding, you may file **comments.** An individual or business or a group who files comments for or against any aspect of the utility's transmission line application is considered a "protestor."

Protestors make a written or verbal statement in support of or in opposition to the utility's application and give information to the PUC staff that they believe supports their position.

Protestors are not parties to the case, however, and <u>*do not have the right to*</u>:

- Make discovery requests and obtain facts about the case from other parties;
- Receive notice of a hearing, or copies of testimony and other documents that are filed in the case;
- Receive notice of the time and place for the negotiations; or
- File testimony and/or cross-examine witnesses;
- Appeal the PUC's decision to state district court.

If you want to file comments, you may either send written comments stating your position, or you may make a statement on the first day of the public hearing. Although public comments are not treated as evidence, they help inform the PUC and its staff of the public concerns and identify issues to be explored. The PUC welcomes such participation in its proceedings.

Intervening in a Proceeding:
Intervenors are parties to the case and may have certain legal rights as a directly affected landowner, including the right to participate in the case and any settlement or mediation relating to the case and the right to appeal any decision of the PUC.

To become an intervenor, you must file a statement with the PUC requesting intervenor status (also referred to as a party). This statement should describe how the proposed transmission line would affect your property. Typically, intervention is granted only to directly affected landowners. A sample form for intervention and the filing address are attached to this brochure, and may be used to make your filing.

If you decide to intervene in a case, you will be required to follow certain procedural rules:

- You are required to respond to discovery requests from other parties who seek information about your position.
- If you file testimony, you must appear at a public hearing to be cross-examined.
- If you file testimony or other documents in the case, you must send copies of the documents to every party in the case.

Intervenors may have an attorney to represent them in a CCN proceeding. If you intervene in a proceeding, you may want an attorney to help you understand the PUC's procedures and the laws and rules that the PUC applies in deciding whether to approve a transmission line.

Stages of a CCN Proceeding:
If there are persons who intervene in the proceeding and oppose the approval of the line, the PUC will refer the case to an administrative law judge (ALJ) at the State Office of Administrative Hearings (SOAH) to conduct a hearing. The hearing is a formal proceeding, much like a trial, in which testimony is presented, and the ALJ makes a recommendation to the PUC on whether the application should be approved.

There are several stages of a CCN proceeding:

- The ALJ holds a pre-hearing conference (usually in Austin) to set a schedule for the case.
- Parties to the case have the opportunity to conduct discovery; that is, obtain facts about the case from other parties.
- Parties file written testimony before the date of the hearing.
- A hearing is held (usually in Austin), and parties have an opportunity to cross-examine the witnesses.
- Parties file written briefs concerning the evidence presented at the hearing.
- The ALJ makes a recommendation, called a **proposal for decision**, to the PUC Commissioners regarding the case. Parties who disagree with the ALJ's recommendation may file exceptions.
- The Commissioners discuss the case and decide whether to approve the utility's application. The Commissioners may approve the ALJ's recommendation, approve it with specified changes, send the case back to the ALJ for further consideration, or deny the utility's application. The decision rendered by the Commissioners is called a **Final Order**. Parties who are dissatisfied with the PUC's decision may file motions for rehearing, asking the Commissioners to reconsider the decision.
- After the Commissioners rule on the motion for rehearing, parties have the right to appeal the decision to district court in Travis County.

Appendix 3

RIGHT TO USE PRIVATE PROPERTY

Before building a transmission line on private property, the utility must obtain the right to enter the land and use it for the transmission line. They typically do this by obtaining an easement from the landowners. Easements convey certain rights to the utility from a landowner.

Utilities may buy easements through a negotiated agreement, but they also have the power of eminent domain (condemnation) under Texas law (Texas Utilities Code § 181.004). Local courts, not the PUC, decide issues concerning easements for rights-of-way. The PUC does not determine the value of property.

The PUC Final Order in a transmission case normally requires a utility to take certain steps to minimize the impact of the new transmission line on landowners' property and on the environment. For example, the order normally requires steps to minimize the possibility of erosion during construction and maintenance activities.

HOW TO OBTAIN MORE INFORMATION

The PUC's online "Interchange" provides free access to documents that are filed with the Commission in Central Records. The docket number of a proceeding is a key piece of information used in locating documents in the case. You may access the Interchange by visiting the PUC's website at www.puc.state.tx.us.
Documents may also be purchased from and filed in Central Records. For more information on how to purchase or file documents, call Central Records at the PUC at 512-936-7180.

PUC SUBST. RULE 25.101, Certification Criteria is available on-line or you may obtain copies of PUC rules from Central Records.

Always include the docket number on all filings with the PUC. You can find the docket number on the enclosed formal notice. Send documents to the PUC at the following address.

Public Utility Commission of Texas
Central Records
Attn: Filing Clerk
1701 N. Congress Avenue
P.O. Box 13326
Austin, TX 78711-3326

The information contained within this brochure is not intended to provide a complete and comprehensive guide to all matters relative to landowner rights and responsibilities in transmission line cases at the PUC. This brochure should neither be regarded as legal advice nor should it be a substitute for the PUC's rules. However, if you should have questions about the process in transmission line proceedings, you may call the PUC's Legal Division at 512-936-7261 and speak to the PUC staff attorney assigned to this case. The attorney may help you with the PUC's rules, but may not provide legal advice or represent you in a proceeding.

Communicating with Decision-Makers:
Do not contact the ALJ or the Commissioners by telephone or email. They are not allowed to discuss pending cases with a party or a protestor. They may only make their recommendations and decisions by relying on the evidence, written pleadings, and arguments that are presented in the case.

Appendix 3

Request to Intervene in PUC Docket No. _________

The following information must be submitted by the person requesting to intervene in this proceeding. This completed form will be provided to all parties in this docket. **If you DO NOT want to be an intervenor, but still want to file comments, please complete the "Comments" page.**

Mail this completed form and 10 copies to:

Public Utility Commission of Texas
Central Records
Attn: Filing Clerk
1701 N. Congress Ave.
P.O. Box 13326
Austin, TX 78711-3326

First Name: ________________________________ Last Name: ________________________________

Phone Number: ___________________________ Fax Number: _______________________________

Address, City, State:____

I am requesting to intervene in this proceeding. As an INTERVENOR, I understand the following:

- I am a party to the case;
- I am required to respond to all discovery requests from other parties in the case;
- If I file testimony, I may be cross-examined in the hearing;
- If I file any documents in the case, I will have to provide a copy of that document to every other party in the case; and
- I acknowledge that I am bound by the Procedural Rules of the Public Utility Commission of Texas (PUC) and the State Office of Administrative Hearings (SOAH).

Please check one of the following:

☐ I own property with a habitable structure located near one or more of the utility's proposed routes for a transmission line.

☐ One or more of the utility's proposed routes would cross my property.

☐ Other. Please describe and provide comments. You may attach a separate page, if necessary.

____

____

____

Signature of person requesting intervention:

____ Date: _____________

Appendix 3

Comments in Docket No. __________

<u>If you want to be a PROTESTOR only, please complete this form.</u> Although public comments are not treated as evidence, they help inform the PUC and its staff of the public concerns and identify issues to be explored. The PUC welcomes such participation in its proceedings.

Mail this completed form and 10 copies to:

Public Utility Commission of Texas
Central Records
Attn: Filing Clerk
1701 N. Congress Ave.
P.O. Box 13326
Austin, TX 78711-3326

First Name: ________________________________ Last Name: ___________________________________

Phone Number: ___________________________ Fax Number: ___________________________________

Address, City, State: ____

I am NOT requesting to intervene in this proceeding. As a PROTESTOR, I understand the following:

- I am NOT a party to this case;
- My comments are not considered evidence in this case; and
- I have no further obligation to participate in the proceeding.

Please check one of the following:

☐ I own property with a habitable structure located near one or more of the utility's proposed routes for a transmission line.

☐ One or more of the utility's proposed routes would cross my property.

☐ Other. Please describe and provide comments. You may attach a separate page, if necessary.

____

____

____

____

Signature of person submitting comments:

____ Date: ____________

Appendix 4

List of Retail Electric Providers

1. AC Boxer Power, L.P.
2. ACN Energy, Inc.
3. AEP Texas Commercial & Industrial Retail Limited Partnership AES NewEnergy, Inc.
4. AmPro Energy, Inc. (pending)
5. Andeler Corporation
6. APS Energy Services
7. BP Energy Company
8. Calpine Power America, L.P.
9. Cinergy Retail Power, L.P.
10. Cirro Energy; Cirro Group, Inc.; Cirro Corp.
11. Commonwealth Energy Corporation
12. Conoco, Inc.
13. Constellation Electric Energy Services Limited Partnership
14. Coral Power, L.L.C.
15. Dynegy Energy Marketing, L.P.
16. ExxonMobil Power and Gas Services, Inc.
17. First Choice Power, Inc.; Certain Energy
18. Green Mountain Energy Company
19. Enron Energy Services, Inc.—Revoked
20. Enron Power Marketing, Inc.—Revoked
21. Entergy Solutions Ltd.
22. Entergy Solutions Essentials Ltd.
23. Entergy Solutions Select Ltd.
24. FPL Energy Power Marketing, Inc.
25. GEXA Corp.
26. Just Energy Texas, LLC
27. Liberty Power Corp. (pending)
28. Mpower Retail Energy LP (pending)
29. Mutual Energy CPL, LP; CPL Retail Energy
30. Mutual Energy SWEPCO, LP; SWEPCO Retail Energy
31. Mutual Energy WTU, LP; WTU Retail Energy
32. New Mexico Natural Gas, Inc. (pending)
33. New Power Company--Suspended
34. Occidental Power Marketing, L.P.
35. PG&E Energy Trading - Power, L.P.
36. POLR Power, LP; Mutual Energy/Texas
37. Pure Power Corporation
38. Reliant Energy Retail Services, LLC
39. Reliant Energy Services Channelview, LLC
40. Reliant Energy Solutions, LLC
41. Republic Power, LP
42. Sempra Energy Solutions
43. StarEN Power, LLC; Texas Star Energy Company
44. Strategic Energy, LLC
45. Shell Energy Services Co., L.L.C. – Suspended
46. Spark Energy, L.P.
47. Tara Energy, Inc.
48. Tenaska Power Services, Co.
49. Texas Commercial Energy, L.L.C.; Hino Energy Service Company
50. Tractebel Energy Marketing, Inc.
51. Tractebel Energy Services, Inc.
52. TXI Power Company
53. TXU Energy Services Company; Assurance Energy; TXU Energy; TXU Energy Retail Company, LP
54. TXU ET Services Company
55. TXU SESCO Energy Services Company; TXU SESCO Energy
56. UBS AG, London Branch
57. Utility Choice, LLC
58. XERS Inc., d/b/a Xcel Energy

Appendix 5

Transaction Scenario Names Inventory

This instruction manual was developed by TX SET for ERCOT and is the implementation guide for conducting business in the deregulated market electric market in Texas.

814_01	**Enrollment Request**	**New CR to ERCOT**	**A and E Scenarios**	**V 1.4**
	This transaction set, from a new CR to ERCOT, is used to begin the Customer enrollment process for a switch.			
814_02	**Enrollment Reject Response**	**ERCOT to New CR**	**A and E Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the new CR, is used by ERCOT to reject an enrollment request on the basis of incomplete or invalid information. This is a conditional transaction and will only be used as a negative response. If an 814_02 Enrollment Reject Response is not received from ERCOT, the CR will receive a transaction 814_05 (Premise Information and Enrollment Response.)			
814_03	**Switch CR Notification Request**	**ERCOT to TDSP**	**A, C, D and E Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the TDSP, is essentially a pass through of the 814_01 information, with the addition of two data elements: (1) the TDSP associated with this Premise and (2) the available switch date.			
814_04	**Switch CR Notification Response**	**TDSP to ERCOT**	**A, C, D and E**	**V 1.4**
	This transaction set, from the TDSP to ERCOT, is used to provide the scheduled switch date that the TDSP has calculated and pertinent Customer and Premise information. The historical usage if requested will be sent using the transaction 867_02.			
814_05	**Premise Information and Enrollment Response**	**ERCOT to New CR**	**A, C, D and E Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the new CR is essentially a pass through of the TDSP's 814_04 information. This transaction will complete the new CR's enrollment request.			
814_06	**Drop Due to Switch Request**	**ERCOT to Current CR**	**A, C and D Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the current CR, is used to notify a current CR of a drop.			
814_07	**Drop Due to Switch Response**	**Current CR to ERCOT**	**A, C and D Scenarios**	**V 1.4**
	This transaction set, from the current CR to ERCOT, is used to accept or reject the drop.			
814_08	**Cancel Switch Request**	**ERCOT to Current CR** **ERCOT to TDSP** **ERCOT to New CR** **Current CR to ERCOT**	**A, B and E Scenarios**	**V 1.4**
	This transaction set... • from ERCOT to the current CR, TDSP, and new CR, is used to reinstate the Customer to the prior CR of record when the switch or Move-Out has been canceled by the Customer. • from the current CR to ERCOT, is used when the Customer cancels a Move-in or Move-out request.			
814_09	**Cancel Switch Response**	**TDSP to ERCOT** **Current CR to ERCOT** **New CR to ERCOT** **ERCOT to Current**	**A, B and E Scenarios**	**V 1.4**
	This transaction set… • from the TDSP, current CR, and new CR, to ERCOT is used to accept or reject the 814_08 cancel switch request and return the Premise to the prior CR of record. • from ERCOT to the current CR is used in response to the Customer cancel of a Move-Out request.			
814_10	**Drop to POLR Request**	**Current CR to ERCOT**	**E Scenarios**	**V 1.4**
	This transaction set, from the current CR to ERCOT, is used when the current CR is dropping the Customer to the POLR.			
814_11	**Drop to POLR Response**	**ERCOT to Current CR**	**E Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the current CR, is used to acknowledge receipt of the 814_10 or reject the current CR's request to drop the Customer to the POLR.			
814_12	**Date Change Request**	**New CR to ERCOT (move-in only)**	**B, C, D and E Scenarios**	**V 1.4**

		ERCOT to Current CR(Move in only) **ERCOT to CSA CR(move-out only)** **ERCOT to TDSP(move-in or move-out)** **Current CR to ERCOT(move-out only)**		
	This transaction set... • from new CR to ERCOT, is used when the Customer requests a date change to the original Move-In request. • from ERCOT to the current CR is essentially a pass through of the date change on the Move-In request from the new CR. • from ERCOT to the Continuous Service Agreement (CSA) CR, is used for a notification of a date change on the Move-Out only. • from ERCOT to the TDSP, is used for notification of a Move-In or Move-Out date. • from the current CR to ERCOT, is used when the Customer requests a date change to the original Move-Out request.			
814_13	**Date Change Response**	**ERCOT to New CR** **Current CR to ERCOT (Move in only)** **CSA CR to ERCOT (move-out only)** **TDSP to ERCOT (move-in or move-out)** **ERCOT to Current CR(move-in only)**	**B, C D and E Scenarios**	**V 1.4**
	This transaction set... • from ERCOT to new CR, is used to acknowledge the requested date change to the original Move-In date on the 814_12 Move-In/Move-Out Change Request. • from the current CR to ERCOT, is used to acknowledge the requested date change to the original Move-In date on the 814_12 Move-In/Move-Out Change Request.			
814_14	**POLR Enrollment Request**	**ERCOT to POLR**	**E Scenarios**	**V 1.4**
	This transaction set, from ERCOT to POLR, is used to notify the POLR of pending Customer enrollment information.			
814_15	**POLR Enrollment Response**	**POLR to ERCOT**	**E Scenarios**	**V 1.4**
	This transaction set, from the POLR to ERCOT, is used in response to the 814_14 POLR Enrollment Response to acknowledge the pending Customer enrollment.			
814_16	**Move-in Request**	**New CR to ERCOT**	**C and D Scenarios**	**V 1.4**
	This transaction set, from the New CR to ERCOT, is used to begin the Customer enrollment process for a Move-In.			
814_17	**Move-in Reject Response**	**ERCOT to New CR**	**C and D Scenarios**	**V 1.4**
	This transaction set, from ERCOT to the new CR, is used by ERCOT to reject an enrollment request on the basis of incomplete or invalid information. This is a conditional transaction and will only be used as a negative response. If an 814_17 Move-In Reject Response is not received from ERCOT, the CR will receive a transaction 814_05 Premise Information and Enrollment Response.			
814_18	**Establish/Delete CSA CR Request**	**CSA CR to ERCOT** **Current CSA CR to ERCOT** **Current CSA CR to ERCOT**	**D Scenarios**	**V 1.4**
	This transaction set... • from the new CSA CR to ERCOT, is used to establish the landlords new CSA CR in the registration system. • from the current CSA CR to ERCOT, is used to remove an existing CSA CR from the registration system. • from ERCOT to the current CSA CR, is used for notification of deletion.			
814_19	**Establish/Delete CSA CR Response**	**ERCOT to New CSA CR** **ERCOT to Current CSA CR** **ERCOT to Current CSA CR**	**D Scenarios**	**V 1.4**

Appendix 5

	This transaction set: • from ERCOT to the new CSA CR is used to acknowledge receipt of the 814_18 Establish/Delete CSA CR Request enrolling the new CSA CR in the registration system. • from ERCOT to the current CSA CR is used to acknowledge the receipt of the 814_18 Establish/Delete CSA CR Request deleting the current CR from the registration system. • from the current CSA CR to ERCOT is use to acknowledge the receipt of the 814_18 Establish/Delete CSA CR Request notifying the current CSA CR that the landlord has selected a new CSA CR.			
814_20	**Create/Maintain/Retire ESI ID Request**	**TDSP to ERCOT ERCOT to Current CR ERCOT to New CR ERCOT to CSA CR**	**F, H and I Scenarios**	**V 1.4**
	This transaction set... • from the TDSP to ERCOT is used to initially populate the registration system for conversion/opt-in. • from the TDSP to ERCOT is used to communicate the addition of a new ESI ID, changes to information associated with an existing ESI ID, or retirement of an existing ESI ID. • from ERCOT to current CR, new CR, and CSA CR, is essentially a pass through of the TDSP's addition, change, or retirement of an existing ESI ID.			
814_21	**Create/Maintain/Retire ESI ID Response**	**ERCOT to TDSP Current CR to ERCOT New CR to ERCOT CSA CR to ERCOT**	**F, H and I Scenarios**	**V 1.4**
	This transaction set: • from ERCOT to TDSP, is used to acknowledge receipt of the 814_20 (Create/Maintain/Retire ESI ID Request). • from the current CR, new CR and CSA CR to ERCOT, is used to acknowledge receipt of the 814_20 Create/Maintain/Retire ESIID Request			
814_22	**Continuous Service Agreement (CSA) (Move In Request**	**ERCOT to CSA CR**	**D Scenarios**	**V 1.4**
	This transaction set, from ERCOT to CSA CR, is used to start CSA service of the ESI ID.			
814_23	**CSA CR Move-In Response**	**CSA CR to ERCOT**	**D Scenarios**	**V 1.4**
	This transaction set, from the CSA CR to ERCOT is used to acknowledge the receipt of the 814-22 CSA Move-In Request.			
814_24	**Move-Out Request**	**Current CR to ERCOT ERCOT to TDSP**	**B and D Scenarios**	**V 1.4**
	This transaction set... • from the current CR to ERCOT, is used for notification of a Customer's Move-Out request. • from ERCOT to the TDSP, it is essentially a pass through of the Customer's Move-Out request.			
814_25	**Move-Out Response**	**TDSP to ERCOT ERCOT to Current CR**	**B and D Scenarios**	**V 1.4**
	This transaction set... • from the TDSP to ERCOT to the current CR, is used to acknowledge the receipt of the 814_24 Move-Out Request. • from the TDSP to ERCOT to the current CR, used to acknowledge the receipt of the 814_04 or 814_25 Move-Out Request.			
814_26	**Ad-hoc Request (supports historical usage request or customer contact update)**	**CR to ERCOT ERCOT to TDSP**	**G Scenarios**	**V 1.4**
	This transaction set... • from the CR to EROCT, is used to request the historical usage for an ESI ID. • from ERCOT to the TDSP, it is a pass through of the CR's 814_26 Ad-hoc Historical Usage Request.			
814_27	**Ad-hoc Response (supports historical usage request or customer contact update)**	**TDSP to ERCOT ERCOT to CR**	**G Scenarios**	**V 1.4**
	This transaction set...			

	• from ERCOT to the CR, is used to acknowledge the receipt of the 814_26 Ad-hoc Historical Usage Request. • from the TDSP to ERCOT, it is essentially a pass through of the TDSP's response.			
867_01	**Conversion/Opt-in Historical Usage**	**TDSP to ERCOT**		**V 1.4**
	This transaction set, from the TDSP to ERCOT is used to report historical usage for conversion/opt-in.			
867_02	**Historical Usage**	**TDSP to ERCOT ERCOT to Current CR**	**A, C, D, E and G Scenarios**	**V 1.4**
	This transaction set... • from the TDSP to ERCOT is used to report historical usage. • from ERCOT to the CR it is essentially a pass through of the TDSP's 867_02 Historical Usage.			
867_03	**Monthly Usage (Interval, Non-Interval, (metered)**	**TDSP to ERCOT ERCOT to CR**	**A, B, C, D, E, J and K Scenarios**	**V 1.4**
	This transaction set... • from the TDSP to ERCOT is used to report monthly usage. • from ERCOT to the CR, is essentially a pass through of the TDSP's 867_03 Monthly Usage.			
867_04	**Initial Meter Read Notification**	**ERCOT to New CR**	**A, C, D and E Scenarios**	**V 1.4**
	This transaction set... • from the TDSP to ERCOT is used to report the initial read associated with a Move-In. • from ERCOT to the new CR is used to report the initial read associated with a Switch or a Move-In. For a Switch, ERCOT will obtain the information from the final 867_03 Monthly Usage. For a Move-In ERCOT will obtain the information from the 867_04 Initial Meter Read Notification from the TDSP.			
867_05	**Distribution Loss Factor Report**	**TDSP to ERCOT**	**??**	**Strawman**
	This transaction set from the TDSP to ERCOT is used to report daily line loss factors.			
810_01	**Settlements Invoice**	**ISO to QSE**	**K Scenarios**	**V 1.3**
	This transaction set, from the ISO/ERCOT to the Qualified Scheduling Entity (QSE), is an invoice for 7 business-days. This transaction triggers an 820 Remittance Advice to be sent back to the ISO/ERCOT.			
810_02	**TDSP to CR Invoice**	**TDSP to CR**	**J Scenarios**	**V 1.4**
	This transaction set, from the TDSP to the CR, is an invoice for monthly Delivery System Charges, Discretionary Service Charges, and when requested by the CR, Construction Service Charges. This transaction set will be paired with an 867_03 (Monthly Usage) to trigger the Customer billing process.			
820_01	**No longer exists**			
820_02	**CR to TDSP Remittance Advice**	**CR to TDSP**	**J Scenarios**	**V 1.4**
	This transaction set, from the Current CR to the, is used to transmit funds. This transaction will reference the 810_02 invoice by ESI ID.			
824	**Application Advice/Reject Response**	**ERCOT to TDSP CR to ERCOT CR to TDSP**	**J Scenarios**	**V 1.4**
	This transaction set is used to reject the 810 Invoice or the 867 Usage.			
650_01	**Basic Service Order Request**	**CR to TDSP**	**I Scenarios**	**V 1.4**
	This transaction set… • from the REP to the Utility, is used to request basic services. • from the REP to the Utility, is used to request a meter change.			
650_02	**Service Order Complete, Complete Unexecutable or Reject Response**	**TDSP to CR**	**I Scenarios**	**V 1.4**
	This transaction set, from the Transmission Distribution Service Provider (TDSP) to the Competitive Retailer (CR), is used to send a completed response to the original Service Order, Complete Unexecutable, Cancel or Change (Update) Request, or Reject the Request.			
650_03	**No longer exists**			
650_04	**Suspension of Delivery Service Notification or Cancellation**	**TDSP to CR**	**M Scenario**	**V 1.4**
	This transaction set from TDSP to CR, used to notify the CR of a suspension of delivery service or to cancel the notification of suspension of delivery service.			
650_05	**Suspension of Delivery Service**	**CR to TDSP**	**M Scenario**	**V 1.4**

Appendix 5

	Reject Response			
	This transaction set from CR to TDSP, used to notify the TDSP of a reject of a Suspension of Delivery Service notification or cancellation.			
148	**Outage Notice and Outage Completion**	**CR to TDSP** **TDSP to CR**	**L Scenario**	**V 1.4**
	This transaction set… • from CR to the TDSP, is used by the CR to notify the TDSP of an Outage. • from the TDSP to the CR, is used by the TDSP to notify the CR that the Outage condition has been resolved or the initial transaction is rejected.			

Appendix 6

Staff White Paper on
Stationary Fuel Cells for Power Generation

Prepared Pursuant to HB 2845 (77th Legislature),
Commercialization of Fuel Cells

August 22, 2002

Public Utility Commission of Texas

Appendix 6

Table of Contents

Figures

Tables

Appendix 6

Executive Summary

This paper describes a policy strategy to expedite the commercial development of stationary fuel cell electric power generation that is consistent with the state's newly restructured electric market. Based on its knowledge of the electric industry, the commission makes the following recommendations with regard to fuel cell commercialization.

1) The state should seek to develop fuel cells as a grid-connected, economically viable distributed generation (DG) option, as this is the most likely way for fuel cell developers to achieve economies of scale and subsequent cost reductions. Incentives for fuel cell distributed generation (FCDG) should be paid per kWh of output metered by the independent system operator (ISO).
2) The state should also seek to develop residential, off-grid and other small-scale applications of fuel cells, as declining costs for FCDG applications should enable similar cost reductions for small-scale applications. Incentives for small-scale applications should be paid as a lump-sum rebate once the fuel cell is activated.
3) Incentives under both programs:
   A) should be larger for "early adopters," decline over time, and reach zero at a specific date;
   B) should be adjusted automatically to account for federal fuel cell subsidies if and when such subsidies are created; and
   C) should include a trigger that reduces the incentive if the market proves robust enough to be self-sustaining.
4) The incentive programs should reflect the state's expectation that fuel cell developers will aggressively reduce costs as the technology matures.
5) The incentive programs should be funded in a way that leverages the objective of encouraging fuel cell development. Those who bear the cost of the program should be relieved of part of that burden if they install and use fuel cells.

Benefits

As a stationary source of electric generation, fuel cells offer a number of benefits both to individual users and to society as a whole. The social benefits – less air pollution, reduced transmission congestion, and the ability to add new generation capacity within an area not in attainment with federal clean air standards – provide the main rationale for public efforts to accelerate fuel cell commercialization. The public benefits are discussed at length by the State Energy Conservation Office in its report to the Legislature on fuel cell commercialization.[1]

The private, owner-specific benefits help identify the quickest and least-cost path to commercial viability, as they constitute elements of built-in value that need no subsidy.

Appendix 6

The relative importance of each kind of benefit will vary from one customer to the next, but generally speaking, they include:

- *Secure back-up power in the event of grid failure;*
- *Efficient power production;*
- *Cushion against natural gas price spikes (less fuel required to produce a kW of power);*
- *Fewer kWh purchased off the grid;*
- *Lower peak kW usage and lower demand charges;*
- *Heat cogeneration; and*
- *The potential for revenues from sale of ancillary services.*[2]

Significant Obstacle

Of all the obstacles to the widespread economic deployment of fuel cells, cost is by far the most significant. *Without significant cost reductions by fuel cell developers, no large-scale economic deployment of stationary fuel cells will be possible*.

Electric Restructuring

State fuel cell policy must be cognizant of and congruent with the changes brought about in the electric industry by Senate Bill 7 (76th Legislature), and should aim to find market solutions to address known challenges.

- *Renewable energy as a study of success*. Senate Bill 7's Goal for Renewable Energy has been so successful that it is being used as a template for similar federal legislation.[3] Simply cloning the Goal for Renewable Energy and the Renewable Energy Credit Trading Program would not be a good idea, however, because there are important differences in the economic maturity of fuel cells and that of renewables – specifically wind power, which is driving the success of renewables in Texas. Nevertheless, lessons can be learned from the success of renewables that, if properly understood and applied, would increase the chances of a similar success with fuel cells.

- *Importance of entrepreneurial effort*. Sustainable commercialization cannot happen without entrepreneurial effort. Financial incentives should therefore reward efficiency and should be designed in such a way as to prevent subsidization of unused or overpriced equipment.

- *Distributed generation*. Large FCDG installations would have a natural market in non-attainment airsheds such as Dallas-Forth Worth and Houston, where reliable electric power is needed but is limited by air quality standards and transmission constraints. For some large customers, FCDG could provide additional flexibility to respond to wholesale power price signals and participate actively in the ERCOT market for ancillary services.

Appendix 6

Proposed Legislative Measures

- *Production incentive*. The FCDG incentive would be paid over a ten-year period on the basis of kWh metered and delivered to the grid. The incentive rate for fuel cells installed during or before the first year of the program would be determined in a proceeding at the commission the year before the incentive was to be available. The commission would set the rate according to the following formula.

  incentive rate = average FCDG market cost – price to beat – federal incentives

  The price to beat rate would be the average general service rate and fuel factor in effect at the time of the commission proceeding, converted to a per kWh equivalent and averaged across all affiliated retail electric providers (REPs). The subsidy level would then decline and would phase out by 2010.

- *Rebate for residential and other small-scale applications.* The small-scale incentive would be paid on the basis of kW capacity. The initial rate would be determined in a manner similar to the per kWh production incentive, except that cost, price to beat, and federal subsidies would be converted to kW equivalents.

- *Goals for new fuel cell capacity.* The goals would represent benchmarks for self-sustainability in the fuel cell market. If the goal for any year were exceeded, the production incentives and rebates would be reduced.

  Funding. Economic activity within the electric sector should be used to finance the state's fuel cell program. Funding mechanisms should be designed so that those who install fuel cells have a smaller obligation to pay for the program. Possible approaches include an emission-based dispatch fee, a flat-rate dispatch fee with credits for fuel cell generation, System Benefit Fund, awarding tradable emission reduction credits for fuel cell generation, and redirecting transmission congestion charges towards fuel cell generators located at points that ease transmission congestion.

Appendix 6

I. Why Fuel Cells?

Fuel cells generate electricity by combining hydrogen and air. This electrochemical process is more thermally efficient than burning fuel to spin a turbine, although some advanced natural gas technologies such as microturbines and modern combined cycle gas turbines have efficiencies comparable to fuel cells. The main byproducts are water vapor and trace amounts of nitrogen oxides, although carbon dioxide can also be released depending on the process used to obtain the hydrogen.

Fuel cell technology lends itself to decentralized, consumer-owned generation ranging in scale from single-home use to larger distributed generation applications. Power generated by the consumer's fuel cell can reduce or replace power that otherwise would have been purchased from a retailer.

As a stationary source of electric generation, fuel cells offer a number of benefits both to individual users and to society as a whole. The social benefits constitute the main rationale for spending public funds to accelerate fuel cell commercialization. The private, customer-direct benefits help identify the quickest and least-cost path to commercial viability.

Social Benefits

- *Less air pollution.* Fuel cells produce power with significantly less NO_x and particulates than is the case with conventional combustion power plants. Table 1 compares emission rates for three distributed generation technologies and Texas averages for total generation.
- *Less transmission congestion*. Fuel cell units are small and relatively easy to site near consumers inside a power distribution area. By reducing the reliance on power imported from outside the area (from West Texas to

Table 1: Emission rate comparison

	Average emission rates (pounds per net MWh generated)		
	NO_x	*SO_2*	*CO_2*
Distributed generation technologies			
Fuel cells (solid oxide)	**0.01**	**0.005**	**950**
Natural gas powered microturbine	0.44	0.008	1,596
Diesel generator	4.7	0.45	1,432
Texas generation from natural gas (1998)	2.18	0.007	1,144
Texas generation from coal (1998)	4.06	9.90	2,349

Sources: Regulatory Assistance Project/National Renewable Energy Laboratory, workpapers for Distributed Resource Emissions Collaborative (http://www.rapmaine.org/DGEmissionsMay2001.PDF); U.S. Environmental Protection Agency, E-GRID 2000 database.

Dallas-Fort Worth, for example), mass deployment of fuel cells can reduce costs incurred at the wholesale level due to transmission congestion, thereby reducing overall power costs for all customers within a transmission congestion zone.

Private Benefits

- *Security.* Like other types of distributed generation, fuel cell distributed generation (FCDG) provides an electric consumer with insurance against grid failure or power curtailment. Hospitals and other emergency services, for example, own distributed generation back-up because of their must-run power requirements. Companies that depend on uninterrupted communication or continuous operation of equipment may also invest in backup power.
- *Efficient power production*. Fuel cells produce more power from the same quantity of natural gas than do most conventional combustion power plants.
- *Cushion against natural gas price spikes.* Because they require less natural gas to produce a kilowatt-hour of electricity, fuel cell generators are less vulnerable to the kind of natural gas price volatility that drove electric bills up in 2000 and 2001. Upswings in natural gas prices result in smaller upswings in total electricity costs for fuel cells powered by natural gas.
- *Demand reduction.* For commercial and industrial customers, charges that are based on peak kW demand can be reduced to the extent that customer-owned FCDG operates when power usage is greatest.
- *Heat cogeneration.* Some types of fuel cells generate heat as they generate electricity. For electric customers who also need heat, a fuel cell can reduce the need to use grid power or natural gas to generate heat at the same time it is generating electricity for the customer's own use.
- *Revenues from sale of ancillary services.* This benefit would most likely be limited to large installations, or to loads acting as resources. FCDG capacity that is consistently greater than what the owner needs can be bid in the ancillary electric services market, where reserve capacity prices are typically between $5 and $15 per MW. Eventually, a large electric customer in ERCOT capable of switching between grid power and on-site FCDG will actually be able to bid part of its *load* on the ancillary services market. If the market price of power is high enough, a customer would be paid by ERCOT to use less grid power as needed to manage the reliability of the system.[4] On-site FCDG could provide some large-use customers in non-attainment areas an additional degree of flexibility that could enable them to participate in these markets.

Appendix 6

Table 2: Distributed generation interconnections reported by utilities

	Year-end 2001 *Number of facilities*	*MW*	*Most common fuel*
Oncor (TXU)	47	154.5	Diesel
Reliant	18	35.1	Natural gas
AEP	7	18.0	Natural gas
Rest of Texas	2	5.0	Natural gas
Total	74	212.6	

Source: Utility reports pursuant to P.U.C. SUBST. R. 25.211(n) on applications received for interconnection and parallel operation of distributed generation.

Distributed Generation

Many of the benefits that an individual customer could obtain by operating fuel cells are the same as for most other distributed generation technologies. Indeed, the strength of the distributed generation market evident in Houston and in the Dallas-Fort Worth area demonstrates a robust market demand for small on-site generation units. (See Table 2.)

Distributed generation (DG) is self-generation. PUC rules define a distributed resource as "a generation, energy storage, or targeted demand-side resource, generally between one kilowatt and ten megawatts, located at a customer's site or near a load center, which may be connected at the distribution voltage level (below 60,000 volts), that provides advantages to the system, such as deferring the need for upgrading local distribution facilities."[5] As customers use more DG, the less power they need to buy and the less power needs to flow through the grid.

Fuel cell technology makes possible a clean and highly controllable distributed generator. The controllable aspect means that it is possible for a fuel cell, with its inverter, to produce firm electrical capacity just as a large gas-fired combined cycle generating plant produces its capacity, but the fuel cell is not as complex. These attributes give FCDG great market potential. Customers who must have clean, dependable power would benefit from this technology to keep critical processes moving. Large fuel cell installations are a natural for non-attainment areas such as the Dallas-Forth Worth area and the Houston area where clean, reliable electric power is needed.

A strong demand for distributed generation already exists in Texas. Moreover, this demand happens to be located in areas of the state with the worst pollution problems and significant transmission congestion. Pollution reduction and alleviation of transmission congestion constitute the two most significant public benefits that are likely to accrue from wider use of fuel cells for power generation. Consequently, a public policy that strategically targets distributed generation applications will coincidentally target the state's worst pollution problems and some of the most serious transmission problems.

The main constraint on future DG is the requirement that new generation meet air emission standards. Setting cost issues aside, these environmental requirements leave fuel cells (along with natural gas microturbines) as the preferred DG option due to its low emissions and high reliability. This would be especially true for DG applications that combine power generation with heat. The fact that it achieves all the benefits of distributed generation with negligible pollution gives FCDG a strong competitive advantage in the state's two most lucrative distributed generation markets: Dallas-Fort Worth and Houston

The Texas Commission on Environmental Quality has put in place streamlined air permitting procedures that allow quick approval of FCDG power plants. For example, when municipally owned Austin Energy installed a 200 kW demonstration DG fuel cell, it received its state air permit in less time than it took to obtain the city building permits it needed.[6]

Ensuring Adequacy of Electric Supply

Perhaps the biggest challenge facing the electric industry in the new world of competition is ensuring that the state's major metropolitan areas will continue to be served by an adequate amount of generation and transmission capacity well into the future. In-migration continues to drive growth in the DFW and Houston metropolitan areas. But installed capacity at major generation plants in these areas will remain virtually the same for many years to come due to the failure to attain air quality standards.

The critical period for electric supply problems is the peak demand months, which in Texas occurs from June through September. The grid must have enough generation capacity to accommodate the one moment during the summer when the most air conditioners are turned on, the most number of refrigerators are running, and the overall demand for power is the highest.

As increasing electric demand pushes ever harder against the limits of nearby generation capacity, the transmission system also begins to press its operating limits at more locations more often. Transmission congestion makes it difficult to move power to everyplace it is needed, and makes it easier to manipulate local shortages and artificially drive wholesale power prices higher.

An effective strategy for staving off supply shortages combines three elements: less consumption, more generation, and more power imports from elsewhere in ERCOT. FCDG is an effective means of reducing the use of grid power, and is one of the few ways of adding more generation in areas where emission standards limit the construction of new fossil fuel generating plants. The major benefits to the grid would include:

- Less need to import power from elsewhere in ERCOT;
- Fewer local distribution bottlenecks; and

Appendix 6

Table 3: Power demand, generation and transfer capacity in 2002

	DFW[a]	*North Zone*	*Houston Zone*
Peak demand (MW)	16,145	24,234	19,584
Available generating capacity (MW)	5,849	24,954[b]	16,524
Excluding plants older than 50 years	5,547		n.a.
Excluding plants older than 30 years	1,745		10,394
Total transmission capacity between major congestion zones at commercially significant constraints (MW)			
South to North (Sandow-Temple)		675	
West to North (Graham-Parker)		884	
South to Houston (South Texas Project-Dow)			758[c]

[a]Dallas, Tarrant, Collin and Denton counties.
[b]Another 2,647 MW is expected to be off-line.
[c]The South Zone is expected to have a generation surplus of about 3,600 MW, most of which will serve demand in the Houston zone via transmission lines that are not congested.

Note: Data are the most current used by ERCOT system planning staff as of this writing and are subject to change. These figures do not take into account plans by AEP and CenterPoint Energy to mothball about 7,000 MW of capacity in Texas. Updated data may be found at http://www.ercot.com/Participants/CSC/index.htm.

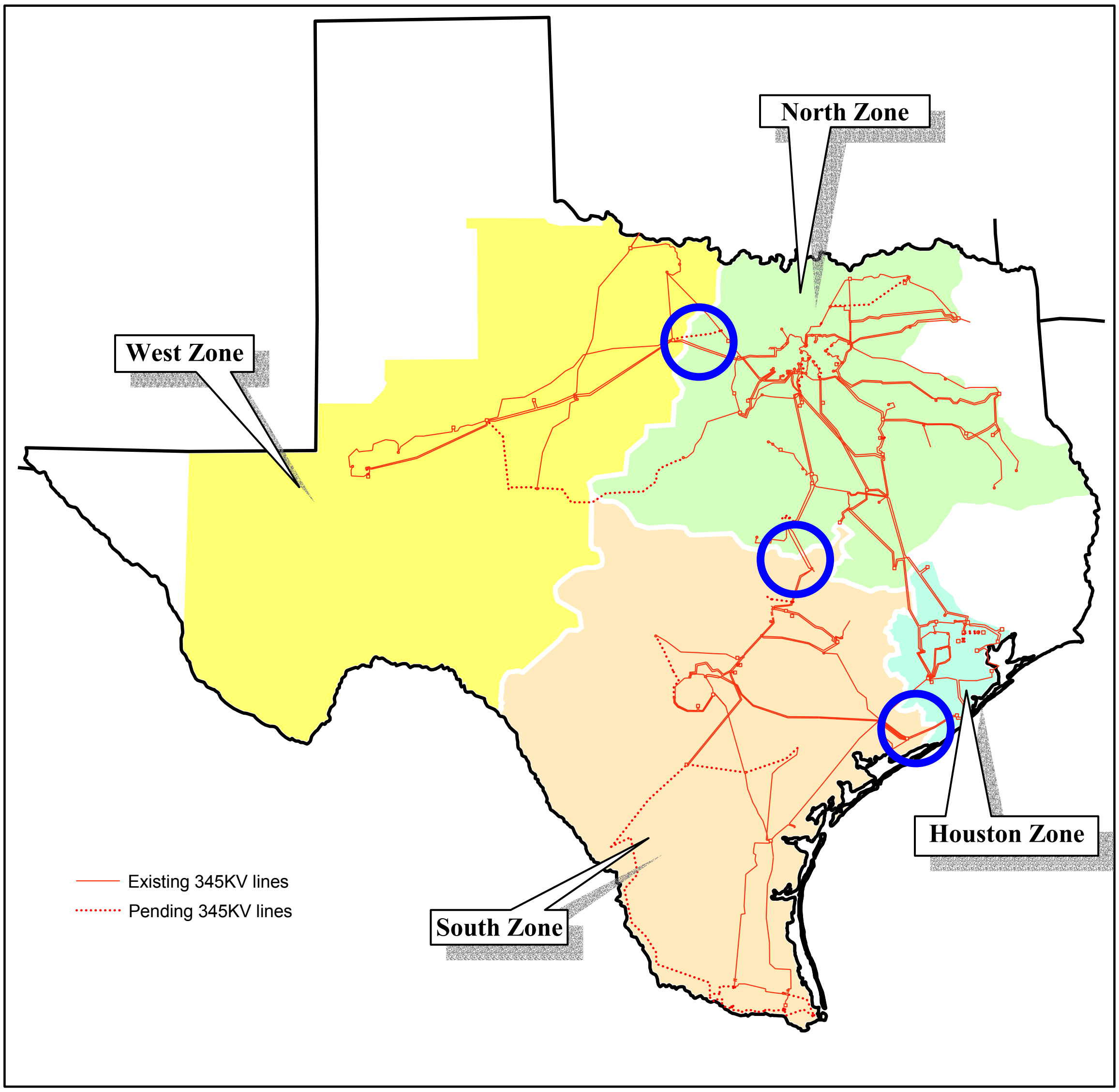
- Fewer opportunities for market manipulation, as a market with many small decentralized resources is harder to monopolize than one with a few large resources.

Table 3 shows how tight demand, generation and transfer capacity are in the four-county Dallas-Fort Worth region (which is part of ERCOT's north congestion management zone) and in the Houston area. ERCOT forecasts that local generators will provide only 36% of that DFW's 2002 summer peak demand. The rest will have to come from elsewhere. There will not be much slack across the north zone, however, as zonal demand is only slightly less than the capacity expected to be available. In addition, transporting power into the north zone is constrained at two points: near Temple to the south and near Graham to the west. Transmission into Houston from the South Zone is constrained on the line from the South Texas Project in Matagorda County to Brazoria County. (See Figure 1.)

Bidders have paid more than $45 million for the right to send power across the two transmission constraints into the north zone, and $30.2 million for rights to the constrained south-to-Houston line. This reflects the scarcity value of transmission into the zone generally, but it also suggests the market value of reducing peak demand through large-scale deployment of FCDG. Eventually, the $45 million will have to be paid by entities serving retail customers throughout the north zone, and these costs will not go away any time soon. Peak demand in the DFW area is expected to grow by 380 MW annually throughout the early part of the decade, but it will be difficult for the area to add new generation to replace its aging capacity. The Commission and ERCOT have identified priority transmission projects that are to be in service by the end of 2002, but a long-term solution needs to include aggressive conservation measures and capacity additions.

FCDG can play an important role in ensuring adequate electric service for the state's metropolitan areas. For this purpose, it is not necessary for FCDG to replace large amounts of conventional generation, because the critical supply problems are most likely to occur at the margin. The incremental capacity that can be provided by FCDG could provide enough of a margin to help avert serious market problems.

Figure 1: ERCOT major transmission lines and 2003 congestion management zones



Circles designate commercially significant transmission constraint points.

II. Obstacles

Cost

The numerous items on the benefit side of the fuel cell ledger are, at least for now, overwhelmingly outweighed by cost. Commercial fuel cell units available today cost around $4,000 per kW of capacity, excluding site costs. Although unit costs are coming down, it will be some time before FCDG is economically competitive.

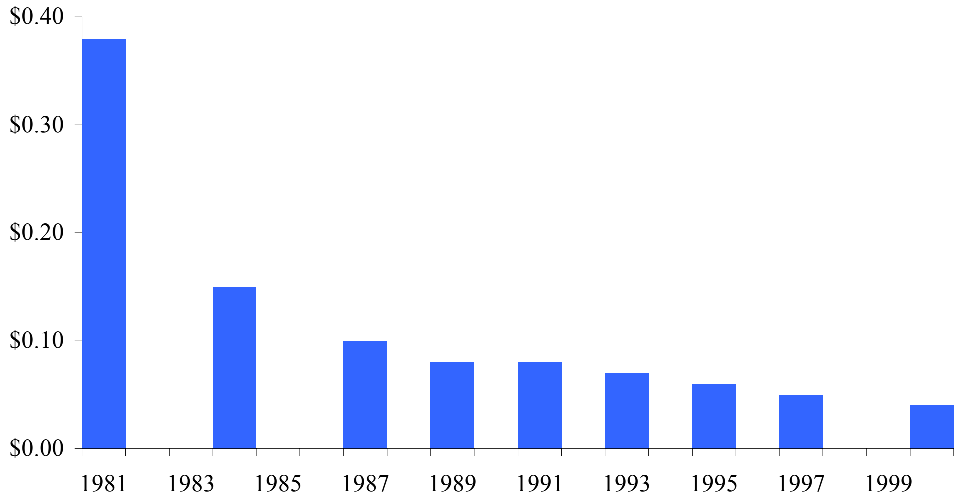
Many of the fuel cell research and development projects now being funded by DOE's involve finding ways to reduce the cost of key components.[7] The budget proposed for DOE includes a 32% increase in funding for fuel cell research and development. DOE's goal is to achieve a cost of $1,000 to $1,500 per kW by the end of 2003, with an ultimate goal of $400 per kW by 2015.[8]

DOE's future cost-reduction targets follow the normal pattern of a commercially maturing technology. As costs fall, unit sales increase. Eventually the industry achieves critical mass: demand is large enough to make economies of scale possible, and costs fall even more.

While this pattern of critical mass has been evident in personal computers and many other high-technology industries, wind power provides an example more apropos of fuel cells. Like fuel cells, wind turbines have been around for a long time. Partly as a result of the OPEC oil embargoes, the federal government accelerated R&D funding for wind turbines in the 1970s. As Figure 2 shows, costs began to fall dramatically in the 1980s, and by the end of the 1990s wind turbines had achieved a magnitude of cost reduction similar to what now is targeted by DOE for fuel cells.

Appendix 6

Figure 2: Historical cost of producing wind power (per kWh equivalent)



Assumes levelized cost at excellent wind sites, and does not take into account the production tax credit ($0.015 per kWh from 1992 through 2001).

Source: American Wind Energy Association, "The Most Frequently Asked Questions about Wind Energy," 1999.

Interconnection

Distributed generation (DG) resources must meet interconnection standards so that they do not pose a reliability risk to the rest of the electric power system. A DG site can include primary energy generation equipment (such as fuel cells); power converters such as induction generators; or power control center and voltage level equipment such as protective devices, metering, and step-up transformers. Connecting these facilities to the electric power system must satisfy the following objectives:

- *Safety*. A DG unit should not create any undue safety hazard for utility personnel, customers or the public.
- *Voltage quality*. The unit must not cause objectionable power quality, voltage regulation or voltage flicker on the utility system and for any customers.
- *Reliability*. The unit should not degrade the reliability of the power system.
- *Utility system over current devices*. The unit must not interfere with the operation of the utility system over current protection equipment.

- *Safety to utility and customer equipment*. The unit should not cause damage to utility and customer equipment during steady state and faulted system-operating conditions.
- *Restoration*. The unit must not interfere with restoration of power on the utility system.
- *Utility system operating efficiency*. The unit must operate at power factors and at generation density levels that maintain utility system efficiency.

In areas where electric utilities are still vertically integrated, it is sometimes difficult for DG customers to obtain an interconnection to the grid. All else being the same, an integrated utility has a fundamental disincentive for DG because it means the customer is buying less of the utility's power. In a restructured market, however, the utility providing the grid connection is not the entity that sells the power.

While concerns have arisen elsewhere in the country, the commission has received very few complaints about transmission and distribution service providers in Texas making interconnection difficult. The commission has attempted to facilitate DG generally by promulgating a set of uniform interconnection standards for all utilities under its jurisdiction. (Municipally owned utilities and electric cooperatives are not subject to these rules, however, and may have different standards.) In short, while interconnection may be a problem elsewhere, it is not a problem in Texas.

Appendix 6

III. Roadmap to Commercialization

The Lessons of Renewable Energy Development

If one looks at how Texas has performed in the area of renewable energy development, two facts are readily apparent. First, a tremendous amount of renewable energy generation – mostly wind power – is being installed in Texas. In its report on wind power development in 2001, the American Wind Energy Association noted that Texas installed more new wind capacity in 2001 (915 MW) than had been installed in the entire country during any previous year. The group observed that "The state more than tripled its wind capacity, and would rank sixth among the nations of the world in wind capacity if it were a country, based on one year's development alone."[9]

Second, unlike most other states, Texas does not directly subsidize the purchase of wind turbines, photovoltaic panels or any other renewable-powered generating equipment. Instead, the Texas approach has been to assure renewable energy developers that they will have a market once they get their hardware up and running. But the developers have to find their own road to that market. And while the market as a whole is guaranteed, no individual's piece is. Developers have to compete among themselves for a share of that market.

The success of wind power in Texas is attributable to three specific factors: a firm and specific legislative goal for renewable energy, a federal renewable energy production tax credit, and – most important of all – aggressive efforts by the wind power industry to reduce its costs of production, as shown previously in Figure 2. These three factors have converged to put wind power developers within profitable striking range of a large market, a significant piece of which is guaranteed until 2019. (Authorized under PURA §35.904, P.U.C. SUBST. R. 25.173 requires retail electric providers to maintain a renewable portfolio standard until 2019).

State policy should encourage the fuel cell industry to follow the example of the wind power industry: a model that relies on entrepreneurial effort and competition. However, ***the state should not simply clone the SB 7 goal for renewable energy and apply it to fuel cells***. ***This would be a recipe for failure.*** It would also be a misunderstanding of the most important lesson of wind power's success: the greatest results tend to occur when entrepreneurial effort and public policy meet each other halfway. The wind power industry reduced its costs, and public policy helped span the rest of the economic gap. This expectation must be built in to the state's fuel cell policy.

One should be mindful of two facts. First, the success of public policy toward renewable energy in Texas has been limited to wind power; technologies that remain costly have not shared in that success. Second, nowhere did wind power enjoy more success in 2001 than it did in the policy environment found in Texas. In other words, the particulars of the state's policy prescription were well-suited to the circumstances of one renewable technology, but not all of them.

Appendix 6

The success of wind power provides insight into *fundamental policy principles* that are applicable to fuel cells, but by no means do these lessons validate using the same program design. The details of what has worked for wind power are not suited to fuel cells, just as a medical treatment that cures one illness may not work against another disease that has similar symptoms but different causes. A fitting policy prescription for fuel cells needs to take into account where the industry is today on its own cost reduction curve. It took the wind power industry many years to turn government-funded research and development into reduced production costs. The current level of federal funding for fuel cell R&D will also require time to mature economically. *The best way for Texas to help hasten the industry's progress down the cost curve is to offer incentives that reflect the expectation that costs will fall over time and that offer the greatest rewards to entrepreneurs who do the best job of reducing their costs*.

Market Principles

In order to be consistent with the new world, state fuel cell policy should recognize the following principles.

- *<u>There can be no sustainable commercialization without entrepreneurial effort</u>*. Good technology and good business strategies are two different things, and both are necessary for the widespread economic deployment of fuel cells. Without entrepreneurial innovation, good technology will remain a high-priced novelty.
- *<u>Entrepreneurs respond to market-pull incentives</u>*. If there is a profit potential, entrepreneurs will find ways to permanently reduce costs and improve services so that they can reach their target market and expand it over time. "Market-pull" incentives are those that improve an investment's anticipated profit stream.
- *<u>Incentives should reward entrepreneurs who do the best job of bringing products to market</u>*. Competition among entrepreneurs accelerates innovation. If the greatest rewards go to those who get to the market first, then each entrepreneur will put forth a greater effort to be first.
- *<u>Incentives should not subsidize unused equipment</u>*. Capital equipment does not produce benefits either for the purchaser or for the economy at large if it is not put to use. Equipment subsidized at the time of purchase allows developers to go home before the job is done; they're no longer "on the hook" to make sure their products replace conventional generation.
- *<u>Incentives should not subsidize overpriced equipment</u>*. If a good idea is executed inefficiently, the inefficiency should not be rewarded. A program that merely offsets economic dead weight will not stimulate long-term commercialization.
- *<u>Commercialization must be consistent with electric restructuring in all respects</u>*. In the new world, regulated electric utilities do not own or dispatch generation. A fuel cell commercialization program that contemplates "electric utilities" in the traditional sense would therefore be inapplicable and irrelevant in Houston, Dallas and Fort Worth – the state's biggest potential markets for fuel cells.

Appendix 6

Policy Outline

The commission recommends that state fuel cell policy include the following elements:

a) Goals for Stationary Fuel Cells

1) 750 MW of FCDG capacity and 250 MW of small-scale capacity by January 1, 2009 with annual intermediate goals[10]:

Year	FCDG Goal (MW)	Small-Scale Goal (MW)	Total
January 1, 2004	37.5	12.5	50
January 1, 2005	150	50	200
January 1, 2006	300	100	400
January 1, 2007	450	150	600
January 1, 2008	600	200	800
January 1, 2009	750	250	1,000

2) If any intermediate goal is exceeded, the incentive level for that category that year would be reduced. For example, if by the beginning of 2005 the state had anywhere between 100 and 150 MW of small-scale capacity successfully installed, the buy-down for additional fuel cells installed in 2005 would be set at the 2006 level, which would be less. (Section (c) describes the proposed buy-down.)

b) Fuel Cell Distributed Generation Production Incentive

1) The incentive would be paid to FCDG owners based on the gross kWh of metered output. The incentive would be paid for a period of ten consecutive years at the rate in effect for the first year of the payment period.

2) The incentive rate for 2004 would be determined by the commission on the basis of three inputs: cost of a typical fuel cell, 2003 price to beat for general service customers (weighted average of all affiliated REPs), and available federal production incentives, all expressed in cents per kWh.

   initial incentive rate = average market cost – price to beat – federal incentives

3) The incentive rate for new installations would decline in equal increments each year after 2004, reaching zero in 2010.

4) Fuel cells earning the production incentive described in this section would not be eligible for buy-down incentive described in section (c).

c) Fuel Cell Buy-Down Incentive for Small-Scale Applications

1) The buy-down incentive would be paid to fuel cell owners at the time the unit was activated, based on the rated capacity of the unit (in kW).

2) The buy-down incentive rate for 2004 would be determined by the commission on the basis of three inputs: cost of a typical fuel cell, 2003 price to beat for residential customers (weighted average of all affiliated REPs), and available federal production incentives, all expressed in dollars per kW.

   initial incentive rate = average market cost – price to beat – federal incentives

3) The incentive rate would decline in equal increments each year after 2004, reaching zero in 2010.

4) Fuel cells that earned the buy-down incentive described in this section would not be eligible for the production incentive described in section (b).

d) **Funding options**. Fuel cell commercialization involves changing the behavior of generators, retailers and customers in the electric sector. Therefore it is appropriate that incentive programs intended to change behavior within the sector be funded from economic activity within that sector, and that the funding be structured in such a way that it augments the public policy goal. Aside from the agency resources needed to put them in place, the alternatives suggested here would not require any commitment of state general revenues.

1) **Emission-based dispatch fee.** Each generating plant in the state would be assessed for each MWh delivered to its transmission grid. The assessment rate would be graduated according to the plant's NO_x emission rate (pounds per MWh) using the following formula

$$\text{plant assessment rate} = \text{plant } NO_x \text{ emission rate} \times \text{statewide annual coefficient}$$

The statewide annual coefficient would be adjusted each year so that total projected revenues would equal actual expenses under the incentive programs during the previous year. Current-year expenses under the incentive programs would be paid under state general revenues, to be reimbursed the following year by revenues from the dispatch fee.

Advantages: Would leverage the policy objective of encouraging fuel cell development. A generator that replaced high-NO_x capacity with low-NO_x fuel cells would both earn the production incentive and reduce the cost of the fee. Annual adjustment would eliminate waste, ensuring that funding was never in excess of what was required. Assessment at the generator level enables the behavior-changing effects to flow throughout the market: retailers would have a greater incentive to buy from low-NO_x suppliers, and customers would have a greater incentive to sign up with retailers who bought from low-NO_x suppliers.

Disadvantage: Would exclude nuclear plants and hydroelectric plants.

2) **Flat-rate dispatch fee**. Per-MWh assessment would be at the same rate for all generators, and would be set each year so that total projected revenues would equal actual expenses during the previous year. Generators who installed fuel cells would receive a credit on the fee based on the amount of fuel cell capacity installed and operated, partially offsetting the cost of the dispatch fee.

Advantages: Similar to emission-based assessment, but would include nuclear and hydroelectric plants in the assessment.

Disadvantage: Price signal would not be as broad as with emission-based assessment, but would be limited to installation of fuel cells.

3) **System Benefit Fund**. Customers would be assessed the cost of the program on a per-kWh basis through the non-bypassable SBF fee.

Advantages: Similar to how some other states fund fuel cell programs. Mechanism already exists.

Disadvantages: Would remove all program burden from generators (they would not be paying any program costs) and would place it entirely on customers. Generators would therefore have less direct financial incentive to adopt fuel cell technology. Would require an increase in the SBF fee.

4) **Emission reduction credits (ERCs)**. Generators and customers who install fuel cells and can document the offset of conventional generation would earn ERCs that could then be sold.

   Advantage: Would link incentives to the market value of emission reduction, which is the main public benefit of fuel cells.

   Disadvantages: Would be limited to areas where emission credits are used. EPA and TCEQ have not yet worked out a method of awarding ERCs for indirect emission reductions. Would require a different incentive structure than what is proposed here. Incentives would have no fixed value because they would vary according to the value of ERCs, making it difficult for a prospective purchaser to accurately assess the costs and benefits of buying a fuel cell.

5) **Redirect transmission congestion charges**. Revenues collected by ERCOT for congestion management would be set aside for fuel cell incentives, rather than being redistributed on a load-share basis as is done now.

   Advantages: Leverages the distributed generation benefits of fuel cells by sending location-appropriate price signals. Higher incentives would be paid to fuel cells installed at transmission-constrained locations.

   Disadvantages: Computationally complex, and would be affected by how transmission congestion costs are assigned. Would require a different incentive structure than what is proposed here. Would not work in non-ERCOT portions of Texas where there is no direct assignment of local congestion costs.

These general elements form a cohesive policy strategy in which the fiscal mechanism leverages the policy objective. On all other details, the Commission makes no recommendation.

Appendix 6

Notes

1 State Energy Conservation Office (SECO), "Accelerating the Commercialization of Fuel Cells in Texas," report to the Texas Legislature pursuant to H.B. 2845, Texas Comptroller of Public Accounts, September 15, 2002.

2 Ancillary services constitute electricity that is reserved and dispatched for grid reliability rather than for customer use. The ability to participate in ancillary service markets would depend on the amount of unused capacity that could be bid and the presence of control systems on the fuel cell assembly that would enable dispatch by the ISO. Only large fuel cell generators would be able to offer ancillary services.

3 See the Daschle-Bingaman Energy Bill, S. 517, 107th Cong., 2d Sess., Sec. 265, "Renewable Portfolio Standard."

4 At the direction of the Commission, ERCOT established its Demand Side Task Force to find ways of enabling load resources – i.e. large customers with interruptible loads – to participate in the ERCOT energy markets. See *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, PUC Docket No. 23220 (Final Order), 2001.

5 P.U.C. SUBST. R. 25.5(19).

6 Larry Alford, Austin Energy manager for distributed generation, presentation to PUC on fuel cells and renewable energy, September 2002.

7 A listing of fuel cell research projects being funded by DOE may be found on the department's Web site at http://www.fe.doe.gov/coal_power/fuelcells/index.shtml.

8 Rita Bajura, Director, National Energy Technology Laboratory, U.S. Department of Energy, remarks in "Workshop Proceedings, Solid State Energy Conversion Alliance," June 2000, Baltimore, Maryland, p. 5 (http://www.seca.doe.gov/Events/Baltimore/SECAFINA.PDF). Also see DOE's Office of Fossil Energy, http://www.fe.doe.gov/coal_power/fuelcells/index.shtml.

9 "Wind Energy Grew Globally at Record Clip in 2001, Report Finds," News release, American Wind Energy Association, March 19, 2002.

10 SECO, p. 24.

Appendix 7

Generation Projects Completed in Texas Since 1995[1]

Map No.	Company	Facility	City (County)	Capacity[2] (MW)	Cogen Host (MW)	Date in Service	Intercon-nection	Region
1	Texas A&M University		College Station (Brazos)	40	40	Jan-96	Brazos	ERCOT
2	CSW Services (wind)		Ft. Davis (Jeff Davis)	6.6		Jan-96	WTU	ERCOT
3	City of Brownsville	Silas Ray	Brownsville (Cameron)	43		Jun-96	BPUB	ERCOT
4	Tenaska IV Texas Partners	Tenaska IV Texas Partners	Cleburne (Johnson)	258		Nov-96	TU/BEPC	ERCOT
5	CSW Energy	Sweeny Cogeneration	Sweeny (Brazoria)	330	90	Feb-98	TNMP	ERCOT
6	Calpine/Phillips	Pasadena Power Plant I	Pasadena (Harris)	240	90	Jul-98	Reliant	ERCOT
7	Borger Energy Associates	Black Hawk Station	Borger (Hutchinson)	254[3]	38	Aug-98	SPS	SPP
8	York Research (wind)	Big Spring Wind Power	Big Spring (Howard)	34		Feb-99	TU	ERCOT
9	FPL Energy (wind)	Southwest Mesa Wind Proj.	McCamey (Upton)	75		Jun-99	WTU	ERCOT
10	American National Wind Power (wind)	Delaware Mtn Wind Farm	Delaware Mtn (Culberson)	30		Jun-99	TXU	ERCOT
11	York Research (wind)	Big Spring Wind Power	Big Spring (Howard)	6.6		Jun-99	TXU	ERCOT
12	Golden Spread/LS Power	Mustang Station	Denver City (Yoakum)	280 198		Jun-99 May-00	SPS	SPP
13	BASF	Freeport	Freeport (Brazoria)	93		Jul-99	Reliant	ERCOT
14	CSW Energy	Frontera Power Station	Mission (Hidalgo)	344 170		Jul-99 May-00	CPL	ERCOT
15	Conoco Global-OxyChem	Ingleside Cogeneration	Ingleside (San Patricio)	440	235	Oct-99	CPL	ERCOT
16	Reliant Energy/Air Liquide/Bayer	Sabine Project	Sabine (Orange)	100[4]	36	Dec-99	Entergy	SERC
17	CPS	A. von Rosenberg	San Antonio (Bexar)	500		May-00	CPS	ERCOT
18	Calpine	Hidalgo Energy Center	Edinburg (Hidalgo)	500		Jun-00	CSW	ERCOT
19	Southern Energy	Bosque County Power Plant	Lake Whitney (Bosque)	308		Jun-00	Brazos	ERCOT
20	LG&E/Columbia-Reynolds	Gregory Power Plant	Gregory (San Patricio)	450	50	Jul-00	CSW	ERCOT
21	Calpine	Pasadena Power Plant II	Pasadena (Harris)	540		Jul-00	Reliant	ERCOT
22	Lubbock Power & Light	J. Robert Massengale	Lubbock (Lubbock)	43		Sep-00	LPL	SPP
23	FPL Energy/Panda Energy	Lamar Power Plant	Paris (Lamar)	1000		Sep-00	TXU	ERCOT
24	Tenaska/PECO Power Team	Tenaska Frontier Gen. Sta.	Shirow (Grimes)	830		Sep-00	Reliant/EGS	ERCOT/SERC
25	ANP	Midlothian I	Midlothian (Ellis)	820 280		Oct-00 Feb-01	TXU	ERCOT

1 The Texas Legislature opened the electric wholesale market in Texas to competition on September 1, 1995.
2 Wind generation facilities are shown at nameplate capacity rating; however, the actual capacity they provide at the time of peak demand may be substantially less.
3 Approximately 216 MW is under 25-year contract to SPS.
4 Sixty megawatts under contract to Alabama Electric Cooperative for three years beginning January 1, 2000.

Appendix 7

Generation Projects Completed in Texas Since 1995 (continued)

Map No.	Company	Facility	City (County)	Capacity (MW)	Cogen Host (MW)	Date in Service	Intercon-nection	Region
26	Union Carbide		Seadrift (Calhoun)	40	40	Nov-00	CPL	ERCOT
27	Texas Independent Energy	Guadalupe Power Plant	Marion (Guadalupe)	1000		Jan-01	LCRA	ERCOT
28	AEP-Phillips	Sweeny (expansion)	Sweeny (Brazoria)	110	35	Jan-01	TNMP	ERCOT
29	Cielo/El Paso Electric (wind)	Hueco Mountain Wind Ranch	Hueco Mtn. (El Paso)	1.3		Apr-01	EPE	WSCC
30	Mirant	Bosque County Power Plant	Lake Whitney (Bosque)	248		Jun-01	Brazos	ERCOT
31	Enron/Austin	Sand Hill Energy Center	Austin (Travis)	180		Jun-01	AE	ERCOT
32	Calpine/Gen Tex Power	Lost Pines I	Lost Pines (Bastrop)	520[5]		Jun-01	LCRA/AE	ERCOT
33	Garland Power & Light	Ray Olinger Power Plant	Garland (Collin)	75		Jun-01	GP&L	ERCOT
34	Orion Energy/Amer Nat Wind Pwr (wind)	Indian Mesa I	(Pecos)	82.5		Jun-01	WTU	ERCOT
35	Tenaska/Coral Energy	Tenaska Gateway Gen. Sta.	Henderson (Rusk)	845		Jul-01	TXU/AEP	ERCOT/SERC
36	FPL/Cielo/TXU (wind)	Woodward Mountain Ranch	McCamey (Pecos)	160		Jul-01	WTU	ERCOT
37	Calpine-Lyondell-Citgo	Channel Energy Center	Houston	160 400	160	Jul-01 Apr-02	Reliant	ERCOT
38	Fina BASF		Port Arthur (Jefferson)	80	80	Aug-01	EGS	SERC
39	Texas Independent Energy	Odessa-Ector Power Plant	Odessa (Ector)	1000		Aug-01	TXU	ERCOT
40	AEP/Eastman Chemical		Longview (Harrison)	440	130	Aug-01	SWEPCO	SPP
41	Exelon/Air Products & Chemicals	ExTex Power Station	La Porte (Harris)	165		Aug-01	Reliant	ERCOT
42	Reliant Energy / Equistar	Reliant Energy Channelview	Channelview (Harris)	172 608	293	Aug-01 Jun-02	Reliant	ERCOT
43	Calpine	Magic Valley Gen. Station	Edinburg (Hidalgo)	350[6] 380		Sep-01 Dec-01	CPL	ERCOT
44	Conoco Global/Dupont	SRW Cogeneration	Orange (Orange)	420[7]	70	Nov-01	EGS	SERC
45	AEP (wind)	Trent Mesa	Trent Mesa (Nolan)	150		Nov-01	TXU	ERCOT
46	AEP (wind)	Desert Sky (Indian Mesa II)	Iraan (Pecos)	160		Dec-01	WTU	ERCOT
47	FPL/Cielo (wind)	King Mtn Wind Ranch	McCamey (Upton)	278		Dec-01	WTU	ERCOT
48	Shell Wind Energy (wind)	Llano Estacado Wind Ranch	White Deer (Carson)	79		Jan-02	SPS	SPP
49	Calpine-Bayer	Baytown Power Plant	Baytown (Chambers)	700	300	Apr-02	Reliant	ERCOT
50	Tractebel	Ennis Tractebel Power Proj.	Ennis (Ellis)	343		Jun-02	TXU	ERCOT

5 GenTex is an affiliate of LCRA. Half of plant capacity will serve LCRA; Calpine will sell the remainder.
6 Magic Valley Electric Cooperative has contracted to buy 246 MW for 2001, increasing by 25 MW in 2002.
7 PG&E Energy Trading will take up to 250 MW over a 10-year period. Approximately 100 MW will be sold into the SERC region.

Appendix 7

Generation Projects Completed in Texas Since 1995 (continued)

Map No.	Company	Facility	City (County)	Capacity (MW)	Cogen Host (MW)	Date in Service	Intercon-nection	Region
51	Constellation Power	Rio Nogales Power Plant	Seguin (Guadalupe)	800		Jun-02	LCRA	ERCOT
52	Calpine	Freestone Energy Center	Fairfield (Freestone)	1040		Jul-02	TXU	ERCOT
53	ANP	Midlothian II	Midlothian (Ellis)	550		Aug-02	TXU	ERCOT
54	FPL Energy/Coastal Power	Bastrop Energy Center	(Bastrop)	535		Aug-02	AE/LCRA	ERCOT
55	ANP	Hays Station	San Marcos (Hays)	550		Apr-02	LCRA	ERCOT
				550		Aug-02		
56	Calpine-Citgo	Corpus Christi Energy Center	Corpus Christi (Nueces)	520	60	Oct-02	AEP-CPL	ERCOT
	56 Projects Completed		***Total Capacity***	***21,905***	***1,747***			

Appendix 7

Generation Projects Under Construction in Texas

Map No.	Company	Facility	City (County)	Capacity (MW)	Cogen Host (MW)	Date in Service	Intercon-nection	Region
57	AES[8]	Wolf Hollow Power Plant	Granbury (Hood)	730		Feb-03	TXU	ERCOT
58	Calpine-Shell	Deer Park Energy Center	Deer Park (Harris)	166	190	Feb-03	Reliant	ERCOT
				169		Aug-03		
				438		Jun-04		
59	InterGen	Cottonwood Energy Project	Deweyville (Newton)	1200		Apr-03	EGS	SERC
60	NRG Energy	Brazos Valley Energy	Thompsons (Fort Bend)	633		May-03	Reliant	ERCOT
61	South Texas Electric Co-op		Nursery (Victoria)	185		Jun-03	STEC	ERCOT
62	Entergy/NTEC[9]	Harrison County Gen Station	(Harrison)	550		Jun-03	SWEPCO	SPP
63	FPL/Cobisa	Forney	Forney (Kaufman)	1789		Aug-03	TXU	ERCOT
64	Austin Energy	Sand Hill P1	Del Valle (Travis)	300		Oct-03	AE	ERCOT
65	Tractebel	Wise County Power Project	Bridgeport (Wise)	800		Jan-04	TXU	ERCOT
66	BP/Cinergy	Texas City	Texas City (Galveston)	570	NA	Feb-04	TNMP	ERCOT
67	Reliant/Jenbacher[10]		Houston (Harris)	23		Dec-02	Reliant	ERCOT
			Conroe (Montgomery)	8		Feb-03	EGS	SERC
	11 Under Construction		***Total Capacity***	***7,561***	***190***			

[8] Twenty-year agreement to sell 350 MW to Excelon Energy Company, and the balance will be marketed by affiliate AES NewEnergy.
[9] Project is 70% owned by Entergy and 30% owned by Northeast Texas Electric Cooperative.
[10] Project currently consists of six landfill gas generation sites. Several smaller sites @ 2 MW could be developed in the future.

Appendix 7

Announced Generation Projects in Texas

Map No.	Company	Facility	City (County)	Capacity (MW)	Expected Construction Date	Expected Date In Service	Region
68	TXU Energy/Cielo Wind (wind)	Noelke Hill Wind Ranch P1	McCamey (Upton)	160	Mar-03	Nov-03	ERCOT
69	Sempra Energy Resources	Cedar Power Project	Dayton (Liberty)	600	Spring-03	Spring-05	ERCOT/SERC
70	Cielo Wind Power/LPL (wind)	Llano Estacado at Lubbock	Lubbock (Lubbock)	2	Jun-03	Jun-03	SPP
71	DFW Airport		(Tarrant/Dallas)	55	2003	2005	ERCOT
				55	2005	2007	
72	Brazos EPC	Jack County Project	(Jack)	600	Jan-04	Jan-06	ERCOT
73	Cobisa	Greenville	Greenville (Hunt)	1750	Spring-04	Spring-06	ERCOT
74	Sempra Energy Resources	MC Energy Partners	Dobbin (Montgomery)	600	Apr-04	Apr-06	ERCOT/SERC
75	Steag Power	Sterne	(Nacogdoches)	950	2Q-04	2Q-06	ERCOT/SPP
76	Texas Petrochemicals		Houston (Harris)	900	2004	2006	ERCOT
77	Orion Energy (wind)		(Culberson)	175	NA	Jul-04	ERCOT
78	Ridge Energy Storage[11]	Markham Energy Storage Center	(Matagorda)	270	NA	Dec-04	ERCOT
79	GE Power Systems (wind)[12]		Sweetwater (Nolan)	400	NA	2004	ERCOT
80	CCNG Inc[13]		San Diego (Duval)	310	NA	2Q-05	ERCOT
81	Dow Chemical		Freeport (Brazoria)	170	NA	Dec-05	ERCOT
82	Tractebel	Ennis-Tractebel II	Ennis (Ellis)	800	NA	Jan-06	ERCOT
83	Austin Energy	Sand Hill P2	Del Valle (Travis)	250	NA	Sum-07	ERCOT
	16 Projects Announced		***Total Capacity***	***8,047***			

[11] Compressed air energy storage project.
[12] Previous Enron Wind project being developed by GE Power Systems.
[13] Compressed air energy storage project which will require 60 to 70 miles of new transmission.

Appendix 7

Delayed Generation Projects[14]

Map No.	Company	Facility	City (County)	Capacity (MW)	Expected Construction Date	Expected Date In Service	Region
84	ANP		El Paso (El Paso)	450	NA	NA	WSCC
85	ANP		Houston (Harris)	2150	NA	NA	ERCOT
86	Calpine	Channel Energy Center exp.	Houston (Harris)	180	NA	NA	ERCOT
87	Calpine	Amelia Energy Center	Beaumont (Jefferson)	800	NA	NA	SERC
88	Cielo	Capital Hill Wind Ranch	(Pecos)	100	NA	NA	ERCOT
89	Duke Energy		(Bell)	500	NA	NA	ERCOT
90	Duke Energy		(Jack)	500	NA	NA	ERCOT
91	Dynegy		Lyondell expansion (Harris)	155	NA	NA	ERCOT
92	Hartburg Power		Deweyville (Newton)	800	NA	NA	SERC
93	Mirant		Weatherford (Parker)	650	NA	NA	ERCOT
94	Texas Independent Energy	Archer Power Partners	Holliday (Archer)	500[15]	NA	NA	ERCOT
95	TXU Energy/Cielo	Noelke Hill Wind Ranch P2	McCamey (Upton)	80	NA	NA	ERCOT
96	Sabine Power I/Port of Port Arthur		Port Arthur (Jefferson)[16]	1000	NA	NA	SERC
97	York Research Group (wind)	Notrees Wind Farm	(Ector, Winkler)	80	NA	NA	ERCOT
	14 Projects Delayed		***Total Capacity***	***7,945***			

---

14 An announced project which does not have a projected in-service date is listed as delayed.
15 Project has been on hold due to lack of transmission into DFW area.
16 Fuel for this plant would be provided by a petroleum coke gasification facility to be constructed in Port Arthur.

Appendix 7

Cancelled Projects

Map No.	Company	Facility	City (County)	Capacity (MW)	Year Cancelled	Region
X1	Steag Power		Ennis (Ellis)	1200	2001	ERCOT
X2	KM Power		(Harris)	1070	2001	ERCOT
X3	Constellation Power	Gateway Power Project	Gilmer (Upshur)	800	2001	SPP
X4	KM Power		Boonville (Wise)	510	2001	ERCOT
X5	BP/Cinergy		Alvin (Brazoria)	70	2001	ERCOT
X6	ANP		Edinburg (Hidalgo)	550	2002	ERCOT
X7	Celanese		Pasadena (Harris)	284	2002	ERCOT
X8	Newport Generation	Palestine Power Project	Palestine (Anderson)	1600	2002	ERCOT
	8 Projects Cancelled		***Total Capacity***	***6,084***		