Pat Wood, III
Chairman

Judy Walsh
Commissioner

Brett A. Perlman
Commissioner

W. Lane Lanford
Executive Director

Public Utility Commission of Texas

January 11, 2001

Honorable Members of the Seventy-Seventh Texas Legislature:

We are pleased to submit our 2001 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act (PURA).

Senate Bill 7 (SB 7), which was enacted in 1999, introduces competition in the retail sale of electricity in Texas, beginning with a pilot project in 2001 and full implementation in 2002. Since the enactment of SB 7, the Public Utility Commission has been working to develop the rules needed to implement this Act. The Commission has completed the rulemaking proceedings that have statutory deadlines or are required to define how the retail market in Texas will operate.

The Commission has also worked with the Independent System Operator for the Electric Reliability Council of Texas (ERCOT) and other regional organizations to develop the trading rules for the wholesale market. ERCOT is making good progress in acquiring the systems and personnel needed to carry out its functions under the Act so that the market will work effectively and customers may switch suppliers seamlessly. ERCOT appears to be on schedule to carry out its role in implementing pilot projects in retail competition beginning in June 2001 and full retail competition beginning in January 2002.

This report describes developments in the Texas electricity industry and our efforts to implement SB 7. The Commission's objective is to create an environment in which there are many producers and sellers, receptive customers, clear commercial rules, and the infrastructure to permit vibrant competition. In addition to reporting on the Commission's activities to create a favorable environment for retail competition, this report describes problems that have arisen in some other areas of the country where retail competition has been introduced. Despite the problems in other areas of the country, we remain convinced that SB 7 will bring vibrant competition to Texas, and that customers and the economy of the State will benefit from it.

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,

Pat Wood, III Chairman	Judy W. Walsh Commissioner	Brett A. Perlman Commissioner

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Report to the 77th Texas Legislature

Scope of Competition in Electric Markets in Texas

Public Utility Commission of Texas
January 2001

January 2001

PUBLIC UTILITY COMMISSION OF TEXAS

REPORT ON THE SCOPE OF COMPETITION

IN ELECTRIC MARKETS IN TEXAS

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INTRODUCTION AND SUMMARY

Senate Bill 7 (SB 7), which was enacted in 1999, introduces competition in the retail sale of electricity in Texas, beginning with a pilot project in 2001 and full implementation in 2002. The bill includes a significant level of detail about how retail competition will be conducted, but it also leaves additional details to be developed. Since its enactment, the Public Utility Commission and interested persons have been working to develop those additional details. The Commission has completed the rulemaking proceedings for which SB 7 provided a statutory deadline and a number of major rulemaking proceedings that will define how the retail market in Texas will operate.

The Commission has also worked with the Independent System Operator for the Electric Reliability Council of Texas (ERCOT) to develop the trading rules for the wholesale market. In addition, ERCOT is acquiring the computer systems needed to make the market work effectively and make it possible for customers to switch suppliers seamlessly. The development of these market rules and computer systems has been a significant task involving ERCOT staff and hundreds of interested persons from the industry. ERCOT appears to be on schedule to have the trading rules and computer systems ready to implement pilot projects in retail competition beginning in June 2001 and full retail competition beginning in January 2002.

This report describes developments in the electricity industry in Texas and the Commission's efforts to implement SB 7. The overall objective of the Commission's implementation effort is to create an environment in which there are many producers and sellers of electricity, receptive customers, clear commercial rules, and the infrastructure to permit vibrant competition. This report describes the principal activities undertaken to create the right environment for retail competition and problems that have arisen in some other areas of the country where retail competition has been introduced.

There are a number of reasons to be optimistic about the success of retail competition in Texas. We have been able to benefit from the experience of other countries and states where retail competition was introduced earlier, and the rules that have been developed in Texas have taken the best features from these other areas and avoided the worst features. Unlike other areas of the United States, where Federal and state policies relating to the electric industry are sometimes inconsistent, regulatory authority with respect to ERCOT rests exclusively with the Texas PUC. Finally, we have benefited from the Legislature's decision in the 1995 session to introduce competition in the sale of electricity at wholesale. The introduction of wholesale competition has yielded billions of dollars in investment in new, efficient generating facilities in Texas. New competitors are entering business in Texas by building new generating capacity, and customers have been and should continue to be the beneficiaries.

The introduction of retail competition has been a difficult process in a number of states that preceded Texas. The problem that has attracted the widest public attention recently has been price increases in California and in the northeastern states. In California, in particular, prices increased dramatically in the wholesale market, and as a result some customers experienced significant increases in the cost of electricity. There are several fundamental causes for these high prices: inadequate electric generating resources to serve customers' needs, restructuring rules that do not encourage competition at the retail level, market rules that precluded retail suppliers from buying power on a long-term or future basis, and lack of response of customers to prices.

Inadequate generation has a predictable result; where demand exceeds supply, prices rise in the wholesale market. Because of the lack of competition in retail sales, retailers have not seen the need to protect their customers from the volatile wholesale electricity prices. Texas, on the other hand, has had significant levels of new generation facilities built, and it is our expectation that supply will be more than adequate to meet customers' needs. The ERCOT Independent System Operator is projecting reserve margins for 2001 to 2003 in the 25 to 30% range, well above the 15% margin that utilities have traditionally relied on. SB 7 also includes provisions that encourage the entry of competitive retailers in the market. The ERCOT wholesale market will also be a market in which power is traded primarily on a bilateral basis on terms that are negotiated by the buyer and seller. This will permit retailers to buy power long-term or buy power for future delivery, and reduce their exposure to the risk of higher prices in the wholesale market. ERCOT is also working to develop mechanisms to convey timely price information to customers and for customers to reduce their consumption when prices are high. These factors should result in adequate electricity in Texas at reasonable prices.

A vibrant wholesale market is important for a retail market to work. The Federal Energy Regulatory Commission (FERC) introduced competition in the wholesale sale of electricity in the rest of the country at the same time that it was introduced in Texas. Wholesale competition has allowed new market participants to build generation facilities and sell the output at market-based rates. In Texas and in a number of other areas new merchant power plants are being planned and built to sell power into competitive wholesale and retail markets. In some areas of the country, however, there are barriers to the development of new generation facilities.

One of the key issues in building generation facilities is the ability to interconnect with the transmission network and transmit power to customers. 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. The construction of new transmission facilities is necessary for reliability purposes, to give new generators access to markets, and to give customers access to many generators. An important element to support vigorous competition is a robust transmission system that provides customers the ability to reach many suppliers and provides suppliers the ability to reach many customers.

In other areas of the country, merchant power plants have had difficulty obtaining transmission service on non-discriminatory terms. The FERC has adopted rules encouraging the formation of regional transmission organizations (RTOs) to address these problems. All of the non-ERCOT investor-owned utilities in Texas are either members of a power pool that is forming an RTO and have committed to join it or have announced plans to join an RTO. The process of developing RTOs and ensuring that their rules are fair and promote wholesale competition has been slow and difficult, however.

Senate Bill 7 recognized that introducing retail competition might result in stranded costs for utilities. The new law created mechanisms for utilities to recover stranded costs prior to 2002 and permits the initial transmission and distribution rates (delivery rates) to include the recovery of the estimated remaining stranded costs. The level of stranded costs that are included in rates also affects the ability of competing retail electric providers to deliver electricity at a competitive price. The estimate of stranded costs to be included in the 2002 delivery rates is based on an administrative determination, using the model that the Commission developed in preparing its 1998 report on stranded costs. Because only *bona fide* market-based valuations of utility generation property provide a valid final determination of actual stranded costs, SB 7 provides for a true-up of stranded costs in 2004, using one or more of four alternative market-based methods to establish the market value of most stranded investments.

The utilities in Texas have filed updated estimates of stranded costs, using the Commission's model. The estimates filed in the spring of 2000 showed that stranded costs had been reduced from about $4.3 billion (in 1998) to about $3 billion. Since then, the Commission directed the utilities to recalculate stranded costs, based on recent changes in the cost of natural gas. Natural gas is a key component in estimating stranded costs, because the cost of natural gas plays such a large role in the expected market cost of electricity. The increases in the cost of natural gas over the past year have resulted in revised stranded cost projections that for most utilities are much lower or negative amounts, based on the Commission model.

Customers are not accustomed to the idea of shopping for electricity, and most states have recognized that educating customers about retail competition is important in helping competition succeed. Senate Bill 7 requires the Commission to conduct a customer education program to educate the public about retail competition. The Commission hired a marketing communications firm specializing in electric utility restructuring to design a customer education plan, with input from an advisory group of representatives from utilities, prospective retail electric providers, and consumer advocates. This firm designed a customer education plan, researched demographics and customer safeguards, summarized best practices from states that had adopted retail competition ahead of Texas, and designed a system to evaluate the effectiveness of the education campaign. In July 2000, the Commission issued a Request for Proposals for the implementation of the Customer Education Plan. The Commission selected Burston-Marsteller, a global public relations company with offices in Dallas and Austin, to carry out the customer education campaign.

The electric industry has been subject to economic regulation for many years. Discontinuing economic regulation of electricity providers raises the question of the continuing roles for government regulation in a competitive market. The Public Utility Regulatory Act, as amended by SB 7 establishes a continuing role for government in the transition to competition and after competition is introduced, and developments in other parts of the country suggest the need for new regulatory functions. The following are areas of government involvement in the electric industry:

- Customer protection
- Market definition and design
- Assessing and controlling market power
- Environmental protection
- Health, safety, and esthetics
- Economic regulation of the remaining monopoly functions

Section 64 of SB 7 requires the Commission to study and make recommendations to the legislature for additional legislation to establish a competitive electric market. The Commission recommends:

- A change to the Gas Utilities Regulatory Act to enhance competition in the electric market.
- A change in the way the System Benefit Fund is administered that to foster the legislative purposes behind the creation of this fund.

The Commission does not recommend any changes or additions to SB 7 or to the Public Utility Regulatory Act[1] that would affect the way retail competition is implemented. The Commission has identified a number of clarifications that could be addressed should the legislature choose to do so.

[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-64.158 (Vernon 1998 & Supp. 2000) (PURA).

SECTION I. IMPLEMENTATION OF SENATE BILL 7

The development of rules and infrastructure for a competitive retail market in Texas has occurred in several tracks:

- the Commission's development of rules to implement SB 7, using rulemaking procedures prescribed by the Administrative Procedures Act, and additional means to enhance public participation;

- the approval of rates for electric delivery service and approval of unbundling plans for the electric utilities, through contested cases at the Commission;

- the development of market rules by the ERCOT ISO through consensus-based procedures involving stakeholders from all sectors of the industry;

- the ISO's contracting for computer and communications systems to operate the ERCOT electrical network and carry out the other functions of an independent organization under SB 7; and

- the development of regional organizations and market rules in non-ERCOT areas of Texas.

A. Adoption of Commission Rules

The Commission began the work of implementing SB 7 shortly after Governor Bush signed the bill into law. The bill explicitly required a number of implementing rules, and other rules were necessary to provide details and certainty for companies that are considering whether to enter the Texas market and for customers who will consider switching suppliers. Several major rulemaking projects were initiated in the third quarter of calendar year 1999, including rules relating to the code of conduct, cost unbundling, and a renewable energy credit-trading program. All of these major rulemaking proceedings were completed by the end of the year, and as these projects were completed, new projects were begun. As of December 2000, the Commission has completed 16 rulemaking projects to implement SB 7. Table 1 charts the progress of the major rules adopted by the Commission.

Table 1: Rules to Implement SB 7

Rules	3Q 1999	4Q 1999	1Q 2000	2Q 2000	3Q 2000	4Q 2000	1Q 2001	2Q 2001
Affiliate code of conduct	Proposed	Adopted						
Business and cost separation	Proposed	Adopted						
Electric reliability standards	Proposed	Adopted						
GLO access	Proposed Adopted							
Distributed generation	Proposed	Adopted						
Renewable energy mandate		Proposed Adopted						
Energy efficiency programs		Proposed	Adopted					
REP, aggregator certification standards			Proposed		Adopted			
Environmental clean-up				Proposed	Adopted			
Retail pilot project				Proposed	Adopted			
Market power mitigation				Proposed	Adopted			
Provider of last resort				Proposed	Adopted			
Customer protection					Proposed	Adopted		
Distribution service terms					Proposed	Adopted		
Capacity auction					Proposed	Adopted		
System benefit fund					Proposed	Adopted		
Price to beat						Proposed	Scheduled Adoption	
ERCOT transmission rules							Scheduled Proposal	Scheduled Adoption
True-up							Scheduled Proposal	Scheduled Adoption

The Commission has adopted rules to define how the retail market will work in Texas and the changes that existing utilities must make to meet the separation requirements in SB 7. These rules establish:

- the requirements for utilities to separate their competitive and regulated activities,
- the terms of a code of conduct to ensure that regulated companies do not undermine competition by providing improper assistance to their competitive affiliates,
- protections for customers against marketing abuses and requirements that retailers provide customers accurate information about the services they offer;
- the criteria for registration of new entities in the retail market, such as aggregators, power generation companies, and retail electric providers, and
- guidelines for renewable energy, energy efficiency, and the System Benefit Fund, which will fund a low-income assistance program and provide funds to the state to make up for lost school tax revenue.

An appendix provides a brief description of the rulemaking projects that have been completed or begun.

The Administrative Procedures Act (APA) prescribes a process for adopting new rules that requires an agency to publish a proposed rule in the Texas Register for public comments, consider the comments that it receives, and then adopt a rule. In adopting a rule, the agency must provide a reasoned justification for its adoption and a response to the public comments. In most of the major rulemaking proceedings to implement SB 7, the Commission has provided significant additional opportunities for interested persons to exchange views and suggestions in developing proposed rules. Once a proposed rule has been developed, the Commission follows the standard APA procedure of publication, comment, and adoption. The additional means for interested persons to participate in the development of rules has resulted in better rules and increased confidence in the rules by those who will have to comply with them.

In developing the rules for the retail competition pilot project, the Commission used the negotiated rulemaking provisions of the APA. The negotiated rulemaking provisions are a formal mechanism for consensual rulemaking, intended to resolve difficult policy issues involving parties with multiple perspectives. The use of this process resulted in a proposed rule in which the participants reached agreement on most of the issues, and it appears to have simplified the adoption stage of the rulemaking proceeding.

B. Approval of Delivery Rates and Separation Plans

In order for retail competition to work, competitive retailers must have access to the utilities' transmission and distribution network on reasonable terms and at reasonable rates. One of the ways that SB 7 will ensure that new competitors have non-discriminatory access to the utilities' delivery networks is to require electric utilities to create separate business units for the power generation, power delivery, and retail sales functions in the retail market.[2] SB 7 also requires the Commission to set the rates for delivery service and determine whether the utilities' plans for separating their business functions are consistent with law.[3] Finally, to encourage competition in energy services, SB 7 requires utilities to discontinue offering competitive energy services.[4] These competitive energy services may be provided by a competitive affiliate of a utility, but they may not be provided by the utility itself. The statute required utilities to file applications for approval of business separation plans, delivery rates, and plans for discontinuing competitive energy services.

Utilities filed their applications for approval of business separation plans and delivery rates in January and March 2000, and these cases have been processed as contested cases. The Commission has adopted procedures to consider a number of generic issues itself, and it has referred the rate cases for the delivery service to the State Office of Administrative Hearings (SOAH) for trial-type hearings on the issues. By December 2000 the Commission had approved the business separation plans for American Electric Power (the new owner of Central Power & Light Company, West Texas Utilities Company, and Southwestern Electric Power Company), Entergy Gulf States, Inc., Southwestern Public Service Company, Texas-New Mexico Power Company, and Sharyland Utilities. Approval of business separation plans was still pending for Reliant Energy and TXU Electric Company.

In connection with the review of the business separation plans, the Commission has reviewed codes of conduct for each utility. SB 7 directs the Commission to:

> adopt rules and enforcement procedures to govern transactions or activities between a transmission and distribution utility and its competitive affiliates to avoid potential market power abuses and cross-subsidizations between regulated and competitive activities both during the transition to and after the introduction of competition.[5]

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[2] PURA § 39.051.

[3] PURA § 39.201.

[4] PURA § 39.051.

[5] PURA § 39.157.

The Commission adopted such rules in the Code of Conduct rulemaking proceeding, and required utilities to file for Commission approval detailed procedures on how they will implement the statutory code of conduct and the Commission's rules. Codes of conduct have been reviewed and approved for most of the utilities.

C. Securitization of Stranded Costs

Senate Bill 7 allows utilities with stranded costs to file an estimate of these costs and begin recovering them in the delivery rates.[6] Utilities with positive stranded costs included estimates in their March 2000 filings to set unbundled electric delivery rates. In these cases, the Commission will consider the estimated stranded costs and, if appropriate, set rates for their recovery. Section II.A of this report provides additional discussion of the quantification of stranded costs. SB 7 also permits utilities to securitize stranded costs and regulatory assets, and the Commission has approved applications of three utilities to securitize regulatory assets.

Securitization is a transaction that permits a utility to receive a one-time, lump-sum payment for stranded costs from investors in lieu of the collecting the costs through its regulated rates over many years. The lump sum payment is financed through the issuance of debt securities to third-party investors. From the investors' point of view, these debt securities exhibit less risk than the utility's common stock, and therefore carry a lower interest rate than the utility's overall rate of return, which includes a return on common equity. The utility's customers pay the principal and interest on the securitized debt through a charge in their electric rates, but the securitized stranded costs are paid at over a shorter period, at a lower rate of return, and without a federal income tax expense. The law establishes an expedited process for review of a utility's application and for expedited judicial review.

Central Power & Light. The Commission approved a request by Central Power and Light Company (CPL) to securitize $764 million of regulatory assets plus transaction costs. Securitization will save CPL's electric customers at least $90 million over the next 12 years. Several parties filed requests for judicial review of the Commission's financing order. The District Court upheld the order, and several parties have filed appeals to the Texas Supreme Court, as is permitted in PURA § 39.303. The Supreme Court heard oral arguments in this case on November 29, 2000.

TXU Electric. The Commission approved a request by TXU Electric Company (TXU) to securitize $363 million of regulatory assets. TXU requested to securitize a much larger amount, $1.650 billion. The Commission concluded that

[6] PURA § 39.201.

the securitization of this larger amount would not meet the statutory standard, because it would not provide tangible and quantifiable benefits to customers. The securitization plan approved by the Commission would save TXU's electric customers least $60 million over the next 12 years. TXU filed an appeal in District Court challenging the decision to approve the securitization of less than the full amount of its request. After the District Court upheld the Commission's decision, TXU and other parties appealed the decision to the Texas Supreme Court.

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

Table 2 shows the Commission's progress in conducting the major cases that are required to implement SB 7.

Table 2: Electric Restructuring Proceedings

	3Q 1999	4Q 1999	1Q 2000	2Q 2000	3Q 2000	4Q 2000	1Q 2001	2Q 2001	3Q 2001	4Q 2001
Proceedings										
Initial Securitization										
Central Power & Light		Filed	Completed							
Reliant		Filed		Completed						
TXU		Filed		Completed						
Competitive Energy Services										
All affected investor-owned utilities			Filed	Completed						
Business Separation										
Reliant			Filed				Scheduled Completion			
TXU			Filed				Scheduled Completion			
All other affected investor-owned utilities			Filed		Completed					
Cost Unbundling										
TXU			Filed					Interim Order	Scheduled Completion	
Reliant			Filed					Interim Order	Scheduled Completion	
American Electric Power			Filed					Interim Order	Scheduled Completion	
Entergy			Filed					Interim Order	Scheduled Completion	
Southwestern Public Service			Filed					Interim Order	Scheduled Completion	
Texas-New Mexico Power			Filed					Interim Order	Scheduled Completion	
Sharyland Utilities			Filed					Interim Order	Scheduled Completion	

D. Market Rules

A key element in successfully introducing retail competition in the sale of electricity is developing a vibrant wholesale market. PURA addresses market rules to some extent by requiring that each area where retail competition is introduced have an independent organization to carry out key functions:

- ensuring equal access to the transmission network,
- ensuring the reliability of the network,
- settling accounts in the wholesale market, and
- managing a registration system, so that customers can switch suppliers easily and efficiently.

In ERCOT, the focus for the development of market rules has been the ERCOT Independent System Operator, which will be the independent organization for this region of Texas.

Two of the key policy choices in designing a wholesale market are the degree of centralization in the market and how electrical production and consumption are matched on a second-to-second basis. Many of the competitive markets elsewhere in the United States and in other countries have centralized power exchanges where producers are required to sell their output and retailers are required to buy their requirements. In other markets, buyers and sellers have greater latitude to buy and sell power on a bilateral basis, through direct contracts between a buyer and seller.

Whether or not there is a power exchange, maintaining reliability requires some degree of centralization in managing electrical production, because production and consumption must match at all times, within fairly fine tolerances. Unlike most tangible products, electricity cannot be readily stored, and a mismatch in production and consumption will change the frequency of the electric system, which can damage equipment. Thus, a system operator (the independent organization) must control production to match consumption on a second-to-second basis.

The ERCOT ISO established a working group to begin work on improving the operation of the wholesale market, even before SB 7 was adopted. When SB 7 was enacted, these discussions re-focussed on how to design a wholesale market to best facilitate retail competition. Hundreds of persons representing dozens of stakeholders have participated in the ERCOT working group discussions. Commission Staff have attended meetings of the working group and its subcommittees and reviewed periodic reports filed by ERCOT on its progress in developing the market rules (referred to as ERCOT protocols). The Commission has periodically solicited comments and held workshops on market design to provide feedback to ERCOT and the working group. Commission Chairman Pat Wood is an *ex officio* member of the board of directors of ERCOT and has participated in discussions of market design issues by the board. Based on this involvement, it appears that there is broad acceptance of the market rules. Some market participants have raised concerns over a few issues, but in general there has been broad support for the rules. On November 1, 2000 the ERCOT ISO filed an application for approval of the protocols. It is expected that the Commission will complete its evaluation of the protocols in the first quarter of 2001.

1. Centralization of Power Sales

As is noted above, one of the key issues in market design is the degree of centralization in the wholesale market. The ERCOT market rules rely on bilateral contracts between buyers and sellers of electricity as the principal mechanism by which power will be traded. This is in contrast to retail markets like California, where there is a central power exchange (PX), and buyers and sellers are required to buy and sell through the PX. A bilateral market gives buyers and sellers broad flexibility concerning the prices and other terms for the sale or purchase of power. In a bilateral market, for example, a retail electric provider (REP) has wide latitude to buy power for long or short terms and buy different packages to match the expected variations in its customers demand for power over the next day, week, month, or year. In a market with a mandatory PX, participants can buy and sell only the products that are traded on the exchange. In practice, the California PX has traded only very short-term power (15-minute intervals) and only recently has begun to trade longer-term and future products.

The longer-term and future trades that are available in a bilateral market provide greater opportunities for buyers to insulate themselves against price volatility in the power market. A bilateral market also offers fewer opportunities for sellers to take advantage of shortages by withholding power or by gaming their bids. A PX must operate under specific written rules, and innovative sellers may be able to find ways to manipulate the clearing price in the market (as some claim has happened in California).

Two concerns about a bilateral market are price discovery and liquidity. If buyers and sellers negotiate a deal in private and do not have an obligation to disclose the price and other terms, it will be difficult for others to know what the market price of power is at any hour or day. Liquidity is related to the volume of trade in a power product. Lack of liquidity will make 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. A vibrant, liquid market is important to permit buyers and sellers of power to adjust their portfolios and provide a price signal to developers, so that they can assess the need for new generating resources in the market.

The volume of wholesale trading has been low in the ERCOT market, and some of the companies that expect to participate in the market when retail competition begins have expressed concern about the lack of liquidity. Today utilities rely to a large extent on generating facilities that they own. From the second quarter of 1999 to the second quarter of 2000, total electricity consumption in ERCOT increased by nearly 5.6%, and short term energy trading increased from 3% of the ERCOT market to 6%. In the latter part of 2000, the level of trading has increased, and several factors are likely to result in further increases in short-term trading: the utility business separations, customers' increasing needs for power, and the beginning of the pilot projects. It seems likely that as the date for opening the retail market in Texas approaches, private exchanges will begin trading standard power products in ERCOT and that trading will increase further. Private exchanges are active in other areas of the country, many of them trading through the Internet, and can offer market-oriented services that would be difficult for a state- or ISO-sanctioned exchange to offer, such as credit management.

2. Controlling the System

Some degree of centralization is required in the wholesale market, because production and consumption must match. Market mechanisms are used to some degree in deploying generating resources to match customers' load. But an ISO or other system operator must have the ability to use generation or loads to control the system frequency and must have reserves to respond to an unexpected event, such as the failure of a generator. These capabilities are referred to as ancillary services. The key ancillary services are regulation and reserves. Regulation is provided by electronic equipment that assesses the status of the system and sends signals to generators to increase or decrease their output. In this way, small second-by-second, uncontrollable variations in system load or generation are offset by controlled changes in the output of the generators that are providing regulation service. Reserves are an "insurance policy" against larger events, such as the failure of an operating generating unit. Reserves are provided by generating units that are ready to quickly and significantly increase their output or by customers who are ready to quickly and significantly decrease their consumption.

Under the ERCOT market rules, the ISO determines the ancillary service needs of the system and controls the resources that provide these services. Each market participant that is scheduling power to serve a group of customers bears responsibility for a proportional share of the ancillary services needed by the system as a whole. The rules permit market participants to arrange for a portion of their ancillary-services responsibility by bilateral contracts, but the ISO has the ultimate responsibility to acquire the services needed to maintain system reliability.

The ERCOT working group has confronted other contentious issues in market design, such as managing transmission congestion. In any electrical system there are times when the lowest-cost mix of generating plants to serve customers 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 generation plants, so that less economical plants must be used instead, the transmission system is congested. With the introduction of retail competition, increased customer demand, and addition of significant levels of new generation in ERCOT, the transmission system is likely to be congested more frequently.

One approach to managing congestion is to identify the transmission pathways that are likely to be congested and charge a congestion fee to the users of a pathway, when it becomes congested. In such a system, priority rights to use the pathway can be sold in advance, so that companies that will need to use the pathways when they are congested can hedge their transmission-congestion risks by buying these rights. The other way to deal with congestion is to charge all users of the transmission system for the costs of operating the less-than-optimal plants. The ERCOT board adopted a compromise approach to congestion management. Initially all users will be charged the costs of operating the less-than-optimal plants, to resolve the congestion. If these costs reach a prescribed threshold, the ISO will implement a system of congestion charges and the sale of priority rights to use key paths.

Scheduling power and loads in ERCOT will require special communications equipment and software and a knowledge of ERCOT's procedures. The ERCOT protocols establish the concept of a "qualified scheduling entity" (QSE), a company that meets these technical requirements to schedule the delivery of energy to customers. A QSE would also have to meet financial requirements to ensure that it can pay for the ERCOT services it uses. A retail electric provider or a power generation company can meet these requirements and act as its own QSE. Alternatively, a third party could meet the requirements and provide scheduling and settlement services to other market participants, serving as their agent at ERCOT for these purposes. The idea of an intermediary was adopted, so that every market participant is not required to meet the scheduling and settlement requirements but could buy QSE services from a qualified third party. Some parties are concerned that there will be a limited number of QSEs or few that will offer service to REPs that serve residential customers. In response to these concerns, the ERCOT protocols have been revised to ensure that there is at least one QSE serving each class of customers. In addition, more than 20 companies have indicated that they intend to qualify as QSEs.

3. Acquisition of Operating Systems

Section 39.151 of PURA describes the functions of an independent organization in the retail market: preserving the reliability of the network, ensuring access to the transmission system, settling accounts, and registering customers, so that they can switch suppliers readily. The ERCOT ISO has begun acquiring the computer resources and personnel it will need to carry out these functions.

One of the early decisions by ERCOT was to consolidate the existing control areas into a single control area that would be operated by the ISO. Control areas are the organizations (today primarily vertically integrated utilities) that are responsible for reliable operation of a geographic section of the electrical network. Consolidating the existing control areas should result in more uniform operating practices throughout the region and centralization of responsibility for reliability.

ERCOT is in the process of acquiring several major computer and communications systems to carry out its broader responsibilities. It is acquiring computers, software, and communications services to reliably operate the control area, to settle accounts for the various services, and to register customers. In addition, it is acquiring computer storage capability to store information relating to operations and settlement, building space to house its expanded operations, and hiring additional staff to carry out these functions. ERCOT currently leases space for its operations center in Taylor, Texas (in Williamson County) and leases office space in North Austin. It plans to buy the Taylor site and build an expanded operations center there and lease space for offices and a backup operations center near Austin Bergstrom International Airport.

E. Independent Organizations in Non-ERCOT Areas of Texas

Portions of East Texas, the Panhandle and the El Paso area are not in ERCOT. SB 7 provides that retail competition will not begin in the El Paso Electric Company service area until 2005. In East Texas, two separate organizations have agreed to a partnership to fulfill the functions of an independent organization. The Southwest Power Pool (SPP) is the reliability organization equivalent to ERCOT for Northeast Texas, Oklahoma, and portions of Arkansas, Kansas, Louisiana, Missouri and New Mexico. Historically, its functions were limited to reliability, but it has begun providing a transmission access function for most of the utilities in this region. Shortly after the enactment of restructuring legislation in Arkansas and Texas, the SPP began working to develop the capabilities necessary to operate as an independent organization under SB 7 for the Northeast Texas region and as a regional transmission organization (RTO) under the rules of the Federal Energy Regulatory Commission (FERC).

In Southeast Texas, Entergy Gulf States, Inc. (Entergy) is the only investor-owned utility providing service. Entergy is affiliated with electric utilities in Arkansas, Louisiana, and Mississippi, and it plans to create an independent transmission company (Transco) that would operate in partnership with and under the supervision of the SPP. The SPP and Entergy have filed applications for approval by the FERC to operate an RTO and Transco in this partnership.

In late 1999, the FERC, which was concerned about the balkanization of the transmission network, directed the utilities that it regulates to form or join regional transmission organizations (RTOs). In much of the country, each utility that owns transmission facilities has its own tariff for transmission service, an information system for customers to obtain information about available transmission capacity, and a system for requesting transmission service. Creating an RTO would result in a centralized control system for the utilities in a region, permitting transmission customers to obtain information about regional transmission capability and request transmission service on a regional basis. The new FERC requirements for RTOs are generally consistent with the provisions of SB 7 relating to independent organizations.

Once in operation, RTOs would permit power to be transmitted across several utility systems through a single tariff and a single scheduling and reservation system. Regional organizations would also result in more efficient operation of the regional transmission system and more rational pricing. While AC transmission systems interact electrically, today there is little coordination among transmission operators on matters such as competing requests for service, managing congestion, and planning transmission facilities to meet the power needs of a growing economy. Finally, regional transmission rates should make it easier and more economical for sales of power that cross several utility systems. Today such sales are subject to transmission charges for each system, rather than a single regional rate (as ERCOT provides).

In the Panhandle, the only investor-owned utility is Southwestern Public Service Company (SPS). SPS merged with Public Service Company of Colorado in 1999, and the resulting company, New Century Energies, merged with Northern States Power Company (NSP) in 2000, creating Xcel Energy. In connection with the NSP merger, SPS agreed to begin offering wholesale transmission service under the SPP regional transmission tariff. SPS has been a member of the SPP for many years, but Xcel planned for the SPS and NSP transmission systems to be operated under the Midwest Independent System Operator. The Midwest ISO is a regional transmission organization that the FERC has approved and that operates in Kentucky, Illinois, Indiana, Iowa, Ohio, Michigan, Minnesota, Missouri, North and South Dakota, and Wisconsin. (The Midwest ISO has members that are in MAAP, MAIN, and ECAR. See Figure 1.) Recently, several of the participants of the Midwest ISO have announced that they intend to withdraw from that organization and join a different RTO in the Midwest. It is uncertain whether the Midwest ISO will remain a viable organization.

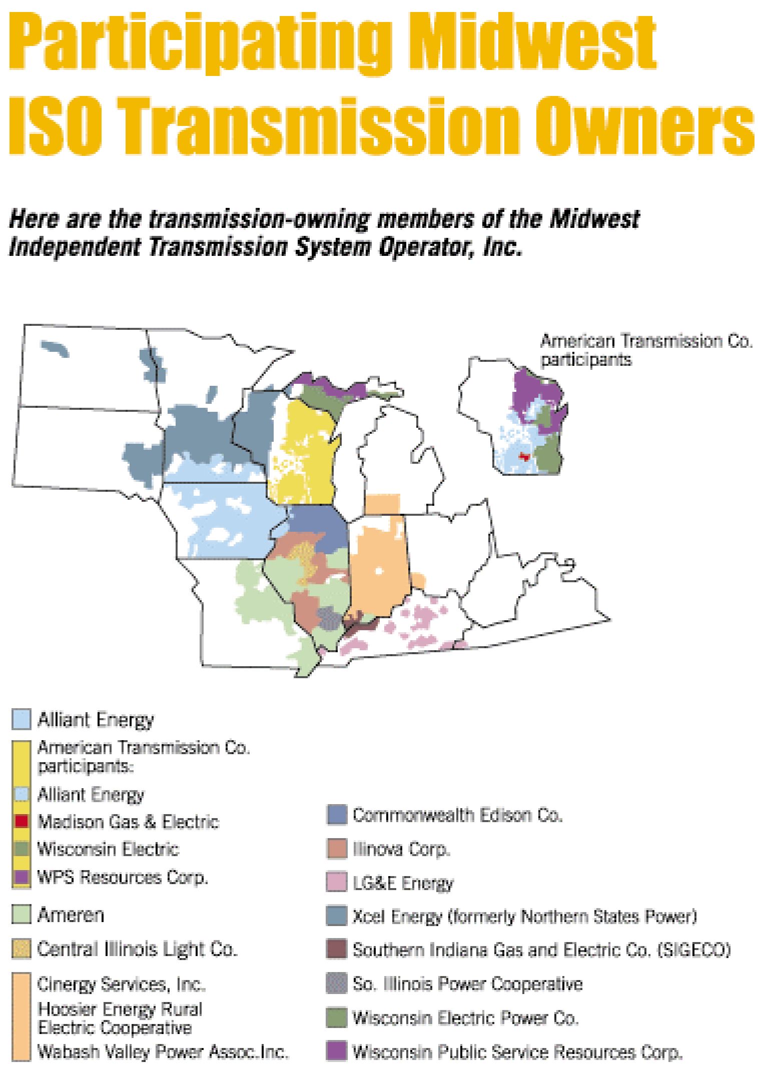

Figure 1: Map of Midwest ISO

SECTION II: COMMISSION ACTION THAT REFLECTS CHANGES IN THE SCOPE OF COMPETITION IN ELECTRIC MARKETS

A. Stranded Investment Update

Stranded investment is defined as *the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market*. Other phrases are also used to describe the concept, such as *potentially strandable investment* and *excess costs over market* (ECOM). Stranded investment is money that utilities have already invested in generating plants that is more than what they would have to invest today to produce the same amount of electricity.[7] These historic costs are not yet stranded, but may become stranded, depending upon changes in the market price of electricity, the speed with which markets become effectively competitive, mitigation efforts by the utilities, and other factors.

Senate Bill 7 provides that utilities are entitled to recover all net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service.[8] The recovery of stranded costs affects retail competition because these costs would be included in delivery rates, increasing the cost of service for competing REPs and reducing the potential savings for customers. The initial transmission and distribution rates set for a utility may include a rate component to recover stranded investments, based on the ECOM model's estimate of potentially stranded costs. Senate Bill 7 provides for a reconciliation in 2004 between the ECOM model's estimate and a market-based valuation of stranded investments. This true-up process allows utilities to use one or more of four market-based methods to establish the value of its stranded investments.[9]

Since the Commission first estimated stranded costs, the magnitude of total stranded investment has been reduced—and in fact, may have become negative. This reduction has occurred through the normal recovery of capital costs in rates over time and special recovery mechanisms authorized by the Commission and by SB 7. In addition, estimated stranded costs are lower today because the price of natural gas is higher. Higher natural gas prices result in a higher expected market

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[7] Technology advancements and changes in the relative costs of different fuels have made it less expensive to produce electricity than was expected at the time that utilities built some of their plants.

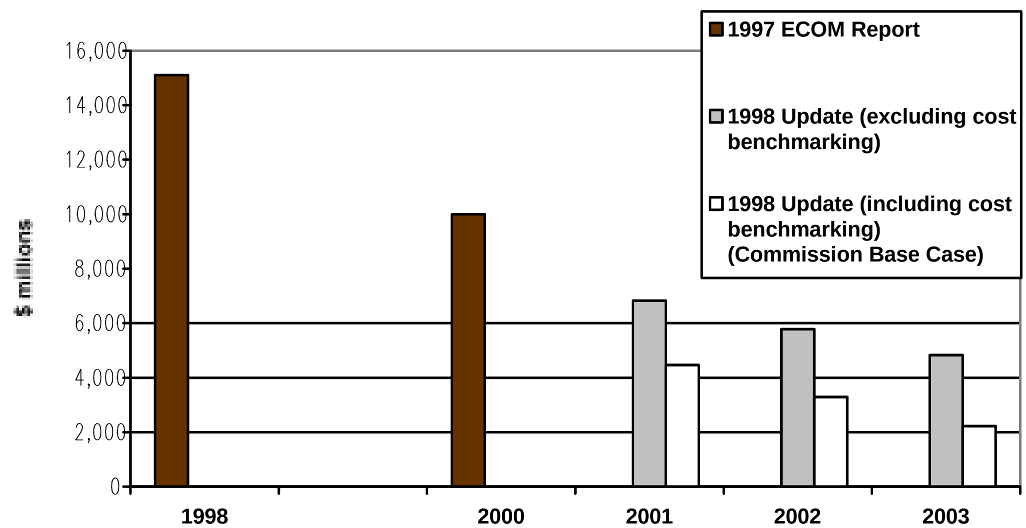
[8] See PURA §§ 39.001(b)(2) and 39.252(a).

[9] See PURA § 39.262(h) and (i). Note in section (i) that some nuclear assets may still be valued with the ECOM model in 2004.

value of electricity in a competitive market, and existing generating plants would be more competitive.

Figure 2 shows summary results from previous Commission reports estimating ECOM. The 1997 report and a 1998 update estimated ECOM on a statewide retail basis.[10] The 1997 report assumed that retail access would begin in either 1998 or 2000, while the 1998 report assumed retail access beginning in 2001, 2002, or 2003. The 1997 and 1998 reports also included ECOM estimates for municipal utilities, electric cooperatives, and river authorities that own generation facilities.[11]

Figure 2 - Summary of Statewide ECOM Results



1998 and 2000 are base case estimates from the 1997 ECOM Report, 2001-2003 are base case estimates from the 1998 Update. ECOM was not measured for a 1999 competition date.

1. Current ECOM Estimates

Since the 1998 update, the Commission has not formally published revised ECOM estimates. The utility companies prepared ECOM estimates pursuant to Section 39.201 of the Public Utility Regulatory Act, which requires that electric utilities include estimates of ECOM as part of the information supporting their proposed tariffs for transmission and distribution service. These cases, which are

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[10] Report to the 75th Texas 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.

[11] The electric cooperatives and river authorities included in the report are wholesale-only utilities, and thus were not included in the total Texas *retail* results.

referred to as unbundled cost of service (UCOS) cases, are pending before the Commission, with final decisions scheduled to be issued by August 2001. PURA specifies that the Commission's ECOM model is to be used in the unbundling cases and specifies many of the assumptions to be used in making the estimates.

Five companies filed estimates of ECOM as part of their UCOS filings—TXU Electric (TXU), Reliant Energy, Central Power and Light Company (CPL), Texas-New Mexico Power Company (TNMP), and Entergy Gulf States. Table 3 summarizes the estimated ECOM amounts for the year 2002 as filed by the companies using the assumptions mandated by the Commission. This table shows the Commission ECOM estimates for each company from the 1998 report and the estimates of ECOM that the companies originally included in their UCOS filings. The Commission updated its natural gas projections during the summer of 2000, and the last column shows the revised estimates (prepared by the utilities) reflecting the Commission's updated gas-price forecast.

Table 3: ECOM Estimates for 2002 Retail Access
($ in millions)

Utility	**1998 ECOM Estimate**	**Initial UCOS Filing**	**Revised UCOS Filing**
TXU	1,058	1,354	(1,454)
Reliant	1,249	815	16
CPL	1,704	593	367
TNMP	176	143	210
Entergy	203	117	119
Total	4,390	3,022	(742)

The non-utility parties in the UCOS cases have argued that the utilities' stranded costs are smaller (or are negative numbers). Negative ECOM would imply that the plant whose book value was originally below market value is now above market value. The utilities, on the other hand, have argued that the ECOM model does not accurately measure their stranded costs and that they still have significant stranded costs. For the five listed companies, the total amount of ECOM *initially* claimed in the companies' UCOS filings was approximately $3.022 billion. After incorporating the revised gas-price forecast into the ECOM model, the companies' total estimated ECOM declined to a total amount of *negative* $742 million. This negative net amount illustrates the sensitivity of the ECOM model to gas-price assumptions. [12]

2. Assumptions Used in Current Estimates

The single most important variable affecting the calculation of ECOM values is the future market price of electricity, which is driven primarily by the future price of natural gas. Other factors, however, also affect estimated ECOM values. For example, PURA requires utilities to use prescribed tools to mitigate (accelerate the recovery of) their ECOM through the year 2001.[13] These tools include the redirection to generation assets of all or part of the depreciation expense relating to transmission and distribution assets and the use of excess earnings to more rapidly depreciate generation assets. Additionally, the Commission has decided to remove from a company's ECOM calculation any regulatory assets for which a securitization order has been issued.

The factors that affect the estimation of ECOM are currently under review in the utilities' UCOS cases. The estimates of ECOM shown in Table 3 are based on the companies' estimates and the assumptions mandated by the Commission. In setting the rates for delivery service in the unbundling cases, the Commission will determine ECOM in accordance with SB 7, and a market-based valuation will be done in 2004 in each utility's true-up proceeding.

B. Effect of Competition on Customers

1. Base Rate Freeze and Fuel Rates

Senate Bill 7 provides for retail competition in the sale of electricity to begin in January 2002, but provisions of SB 7 already have had an effect on customers. SB 7 required that electric utilities freeze their base rates from September 1, 1999 until retail competition begins.

For Texas customers, the most significant recent event affecting the electric industry has been the significant increase in the price of natural gas over the last 18 months. In Texas the baseload electrical needs for most customers are supplied by coal-fired or nuclear generating plants, but electric consumption above a certain level is supplied by gas-fired facilities. Gas is the fuel for a significant portion of the electricity produced in the state. In 1998, for example, 40% of the electrical energy produced in the state was from gas-fired facilities. For 1998 and 1999, the

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[12] TXU and other companies have argued that PURA does not explicitly contemplate the possibility of negative ECOM. Accordingly, they have taken the position that, as a practical matter, negative ECOM does not exist and any calculations showing a negative amount of ECOM should be rounded to zero.

[13] See PURA § 39.254.

average wholesale gas price was just under $2.20 per mmbtu. Prices began increasing during the summer of 1999 and have risen significantly in 2000. Spot prices reported in December were in excess of $7.00 and are expected to remain high during the winter.

Electric utility rates in Texas include a base rate and a fuel factor, and PURA and the Commission's rules permit utilities to adjust their fuel factors to reflect changes in the prices of fuel. While base rates are frozen for investor-owned utilities under SB 7, fuel rates may be changed. As gas prices have risen, electric utilities have increased their fuel rates to recover the fuel costs from customers. Table 4 shows representative increases over the past year in total rates. These changes are based on changes in fuel factors related to natural gas price increases. Utilities have requested additional increases in their fuel factors, so customers are likely to experience additional increases in electric rates. The increases in fuel rates are not a consequence of retail competition but of events that affect supply and demand in the natural gas market.

Table 4: Electricity Price Increases, November 1999 to November 2000

Utility	**Percentage increase in residential rates**	**Percentage increase in commercial rates**
Central Power & Light	17	24
Entergy	9.5	12
Reliant HL&P	10	15
Southwestern Public Service	13	14
TXU	7.7	8.7
West Texas Utilities	21	27

Gas prices are projected to fall next spring and summer, but they are likely to remain above 1998 and 1999 levels. The new electric generating facilities that are being installed in Texas are more fuel-efficient than the older units. This means that they will produce more electricity from the same volume of gas, compared to the older units, and this higher efficiency should be a factor that will help hold down electricity prices.

2. Competitive Energy Services

As of September 2000, electric utilities were required to separate regulated utility activities and competitive energy service activities that are widely available in the competitive market. As a result, utilities have discontinued services that can be provided on a competitive basis, and other companies have a greater opportunity to provide such services to the utilities' retail customers. Among the services that are considered competitive are security lighting, energy efficiency, energy management, load management services, and transformer and substation maintenance.

3. Energy Efficiency

PURA §39.905 requires electric utilities to achieve energy savings of at least 10% of the utility's annual growth in demand in Texas by January 1, 2004. To achieve this goal, utilities must provide incentives to energy services companies or retail electric 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. In addition to energy service companies, retail electric providers and customers may take advantage of the standard offers. The incentive typically does not cover the full cost of the measures that are installed, and the customer usually must make a contribution. 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. The Commission adopted a rule to implement §39.905 on February 24, 2000.

The objective of the rule is the installation of long-lasting energy efficiency measures that will result in reduced energy consumption and lower energy bills for Texas customers in all customer classes. Beginning in 2000, electric utilities are to implement energy efficiency programs to the extent that the Commission has previously included demand-side management funds in their rates. On January 1, 2002, when retail competition begins, all utilities will implement standard offer or market transformation programs, and their new transmission and distribution rates will provide funding for the programs.

Following the adoption of the rule, the Commission approved statewide templates for the standard offer and market transformation programs. In addition, the Commission 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 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. The Commission approved the following templates:

- Commercial and Industrial Standard Offer Program;
- Residential and Small Commercial Standard Offer Program;
- Energy Star Homes Market Transformation Program;

- High Efficiency Residential Windows Market Transformation Program;
- Load Management Standard Offer Program;
- Hard-to-Reach Standard Offer Program;
- Air Conditioning Distributor Market Transformation Program; and
- Air Conditioning Installer Information and Training Market Transformation Program.

C. Customer Education Program

A key element in creating customer receptiveness to retail competition is letting them know that competition is coming and how it will work. Customers are not accustomed to shopping for electricity, and SB 7 directed the Commission to implement an educational program for customers to let them know about the opening of the retail electric market and the customer choice pilot program.[14] Section 39.902 requires that the education campaign:

- Be neutral and non-promotional and provide customers with the information necessary to make informed decisions relating to the source and type of electric service available for purchase;
- Inform customers of their rights and of the protections available through the Commission and the Office of Public Utility Counsel;
- Not duplicate customer information efforts undertaken by retail electric providers or other private entities; and
- Not target areas served by municipally-owned utilities or electric cooperatives that have not adopted customer choice.

The Commission hired High Point/Franklin, a marketing communications firm specializing in electric utility restructuring, to design the Customer Education Plan with assistance from Commission staff and the Customer Education Working Group, an advisory group of representatives from utilities, prospective retail electric providers, and consumer advocates, among others. High Point/Franklin conducted demographic and customer research, evaluated best practices from states that had adopted retail competition ahead of Texas, and designed a Customer Education Plan, which the Commission approved.

The research included interviews with more than 40 opinion leaders, a series of focus groups with customers, and a telephone survey of 1,100 residential and 400 business customers of investor-owned utilities. Key research findings include:

[14] PURA § 39.902(a).

- While specific knowledge of electric competition is quite low, interest in this subject is relatively high;
- There is a significant level of confusion regarding how electric competition will work;
- Texas customers want educational information in simple, easy-to-understand language, with no editorializing. Their message is, "Tell me, don't sell me";
- Customer expectations for savings may be exaggerated, and
- Both residential and business customers regard the Public Utility Commission as the most trustworthy voice to provide a public education program.

Important "lessons learned" from other states conducting electric restructuring and public education activities include the following:

Timeliness – The Texas Customer Education Plan must be able to provide customers the information they need, when and where they want it.

Measurability – Pre-established measurement systems are essential to evaluate educational efforts.

Flexibility – The flexibility to redirect efforts and resources based on feedback gained from periodic performance measurement is crucial.

Leveraging the Plan – The Customer Education Plan should enable other organizations and groups to connect to the Plan and use its concepts and messages to leverage their own communications efforts, thereby increasing its overall effectiveness. The Plan must lead the communications activities of all utilities and retail electric providers, not only to prepare the marketplace, but also to set the standard for objectivity and clarity.

On July 21, 2000, the Commission issued a Request for Proposals to implement the Customer Education Plan. Twelve bidders submitted bids to conduct the education campaign, and on October 19, 2000, the Commission selected Burston-Marsteller to manage the campaign. Burston-Marsteller is a global advertising and public relations firm with offices in Dallas and Austin and significant experience in electric competition and energy issues.

The Customer Education Plan calls for coordinated execution of an integrated communications campaign. It will require a range of communications tools working in coordination to provide accurate, timely information to Texas electric customers. These tools include:

- An **Overall Campaign Identity** that will provide cohesion and focus to all campaign communications;
- **Paid Advertising** that will act as the central awareness-building tool;

- **Promotions** that help make the campaign more “tangible” to the customer;
- **Public Relations** activities, particularly media relations, which will precede all major communications efforts;
- **Community Outreach** activities targeted at Community-Based Organizations, which will form the primary channel to reach traditionally under-served populations such as low-income and non-English-speaking customers;
- **Printed Education Materials** to perform the primary educational function in this campaign;
- A **REP Selection Process** designed to act as a catalyst to convert customer awareness and interest into the selection of a retail electric provider, or to request information from a range of retail electric providers;
- An **Electric Competition Answer Center** with a toll-free telephone number and trained representatives to answer questions in English and Spanish and take requests for printed materials;
- An **Electric Competition Web Site** that will enable customers to access a wide range of information on electric competition;
- A **Fulfillment Process** to provide customers printed campaign information; and
- **Campaign Measurement** to provide the Commission timely, objective feedback into customer response to the campaign.

D. Formation of Market Surveillance Unit

It is important in emerging electricity markets to oversee the design and operation of the market to ensure that it works for the benefit of customers. Introducing competition in electricity is more complex than introducing competition in many other industries, for several reasons:

- reliability and vibrant competition depend on the efficient operation of the AC transmission network, which is technically complex to plan and operate; and
- the addition of generation and transmission facilities has long lead times and significant capital requirements.

Market surveillance, also referred to as market oversight or market monitoring, is a required function of all regional transmission organizations under by the Federal Energy Regulatory Commission (FERC) rules. In addition, all existing FERC-regulated independent system operators (ISOs) are subject to market oversight to identify market design flaws and abuses and propose remedial actions.

Market oversight has been a major concern in ERCOT, particularly for smaller market players and customer representatives. These groups have supported the creation of a strong market surveillance unit (MSU). On the other hand, major market players in ERCOT want to avoid what they perceive as the problems of ISO-operated MSUs in other regions, where MSUs have adjusted market-clearing prices after-the-fact, with significant financial consequences for market participants.

The ERCOT stakeholders agreed to place market oversight responsibility under the Commission, rather than under the ERCOT ISO. This role is consistent with the Commission's authority to address market power under PURA §§ 39.155 and 39.157. As market monitor, the Commission will play a crucial role in determining whether market rules have been violated and whether they need to be revised to ensure fair and efficient markets. Successfully implemented, the Commission's market oversight role will assure that the ERCOT market is attractive for competitors and results in reliable, reasonably-priced electric service.

Recent experience in the California electricity markets illustrates the potentially severe consequences of inefficient markets.[15] Soaring electricity prices and bills have led to suggestions of improper conduct and a number of investigations of the operation of the California markets, including investigations into the behavior of market participants. The California ISO and Power Exchange have responded to high prices by substantially reducing the price caps in the power markets they operate. The California experience highlights the importance of market oversight. The Texas PUC is developing the capability to monitor market activities, assess the need for revisions to market rules, and identify improper conduct in wholesale and retail electricity markets. The Commission is working proactively to avert market design flaws and market abuses before they harm the market or Texas customers.

The Commission's MSU will watch for inordinate price spikes and price volatility in various electricity markets and investigate complaints raised by customers or other market participants and, if necessary, recommend remedial action by ERCOT or the Commission. The Commission's MSU will monitor several electricity markets, including:

1. Retail electricity markets;
2. Bulk power markets;

[15] According to an Oil & Gas Journal online story, published on October 13, 2000, California's wholesale electricity costs were a record $4.5 billion in August, topping by $1 billion the previous record set in June 2000. Through August, wholesale power costs, including ancillary services, totaled about $14.2 billion. For all of 1999, costs totaled $7.3 billion.

3. Ancillary services markets; and
4. Transmission markets, with particular attention paid to congestion management and congestion rights.

The Commission recognizes that market conditions will change, and that market rules will evolve, in response to the changing conditions. The MSU will have to understand the changing conditions, to help assure that the markets remain fair and efficient.

E. System Benefit Fund

Senate Bill 7 created a System Benefit Fund (SBF) to address specific issues associated with the transition from regulated electric service to retail competition. Under PURA § 39.903(d), the Public Utility Commission is required to report to the Legislative Oversight Committee "if the system benefit fund fee is insufficient to fund the purposes" for which it was created. To date, the fee that supports the SBF has been sufficient, but its sufficiency over the next few years is uncertain. The start of customer choice on January 1, 2002 is more than a year away, and there are several areas of uncertainty that make it difficult to accurately project available fund balances and expenses when a competitive retail market opens in Texas. One complication relates to a lack of Commission authority to carry funds over from one biennium to the next under the current legislation. The Commission has requested an appropriation for FY 2002 and FY 2003 based on the maximum allowable rate for the SBF, in light of the uncertainty about the costs that will be incurred by the fund, uneven cash-flows, and the need to establish an adequate level of working capital.

1. Background

The SBF was created pursuant to Section 39.903 of the Texas Utilities Code. Under that section, the fund was established as a trust fund to be held by the Comptroller and administered by the Commission. In subsequent legislation, HB 3084, 76th Legislature, Reg. Session, relating to the creation and re-creation of funds, the system benefit fund was repealed as a dedicated fund and made part of the general revenue fund. It is currently referred to as an "account" within the general revenue fund.

The SBF funds four different programs:

1. Compensation for the state and school districts for losses in property values of the utilities' assets directly caused by the electric industry restructuring;
2. An electric rate discount for low-income customers;
3. A targeted low-income energy-efficiency program administered by the Texas Department of Housing and Community Affairs (TDHCA); and

4. Appropriations to the PUC for customer education programs, and to the PUC and Office of Public Utility Counsel (OPUC) for administrative costs.

The source of revenues for the fund is a fee based on the kilowatt-hours of electric energy used. The PUC sets the level of the fee on an annual basis, up to fifty cents per megawatt hour (Mwh) but has the latitude to set the fee up to sixty-five cents per MWh during 2002 through 2006, if necessary to fund at least a 10% rate reduction for low-income customers.

The Commission is adopted a rule in December 2000 to define how the Commission will annually set and collect the fee and direct payments for programs. The only expenditures from the SBF to date have been amounts directly appropriated to the Commission and OPUC to implement SB 7. During the fiscal years 2000 and 2001, the Commission directed the investor-owned utilities to pay their share of the required amounts into the fund. In FY 2000, the Commission set the fee at $0.005/MWh and collected $1,116,695.00. The 2000 funding level was roughly one-one hundredth of the level authorized in SB 7. For FY 2001, an initial assessment collected $13,213,720.00. Twelve million dollars from the FY 2001 revenue is earmarked for customer education. The Commission issued an order on December 1, 2000 to collect $65,868,783 in FY 2001 in a supplemental assessment, to compensate the state and school districts for losses in property values. This supplemental assessment will increase the amount collected in FY 2001 to $79,082,503, or about $0.34 per MWh. The 2001 assessment would be about two-thirds of the level authorized in SB 7.

During 2000, property tax appraisers for several school districts significantly reduced the appraised value of electric generating facilities. In accordance with PURA § 39.901, the Comptroller on August 31, 2000, certified that $6.405 billion in lost property value was directly related to electric restructuring. On October 17, 2000, the Texas Education Agency (TEA) determined, based on the Comptroller's certification, that $65,868,783 should be paid out of the SBF as compensation for lost tax revenue.[16] Since the property valuations were made in 2000, natural gas prices have increased, and the market values of nuclear and coal-fired generating facilities have increased. It is possible that the 2001 property valuations will reflect higher utility property values, and require a lower contribution from the SBF.

2. Projected Sufficiency of the SBF Fee

There are several factors that cause uncertainty about whether the SBF will be large enough to fully fund the programs for which it was created. The most significant area of uncertainty is estimating funding for school property-tax losses, which depends on whether the property-tax loss mechanism provides a one-time

[16] This number is subject to a final recalculation in April 2001.

payment or on-going payments, until the 2006-2007 school year. The source of the uncertainty is PURA Section 39.901. Subsection (a) describes how to calculate the loss in revenue and implies that tax losses would occur only once, while subsection (h) establishes the funding mechanism through the 2006-2007 school year. Subsection (a) provides that "the comptroller shall certify to the Texas Education Agency any property wealth reductions, determined by taking the difference between current year and prior year appraisal values attributable to electric utility restructuring."

The introduction of retail competition reduced the appraised value of certain power plants in 1999, the year that SB 7 was enacted. Applying the subsection (a) formula for 1999, the comparison of the current year and prior year (1998) appraisal values showed a significant reduction in value, related to the introduction of competition. If the 2000 values remain the same as the 1999 values, there would not be a reduction in appraised value, and no payment would be due to the Education Agency. If the values remain the same through the 2006-2007 school year, there would be no additional payment into the foundation school fund.

When competition begins the SBF will also fund the electric rate discount and energy-efficiency programs for low-income customers. It is expected that the cost of the energy-efficiency program will be established by an appropriation in the 2001 legislative session, but the demands related to the low-income rate discount cannot be predicted with accuracy. Much will depend on the number of potential customers for the discount program, and the extent to which eligible customers take advantage of the discount. Similarly, it is difficult to quantify the amount of the discount a customer will receive, because of variations in customer consumption of electricity. The uncertainty concerning the nature of the obligation for property-tax losses and the level of energy-efficiency expenditures could be eliminated by legislative action during the 2001 session. The uncertainty about the level of expenditures for the low-income discount will remain until after retail competition begins.

Table 5 shows current projections of revenues and expenditures from the SBF during the first year of customer choice, under two scenarios. The first scenario assumes that:

- the school-funding obligation is paid off before 2002 and is not a continuing obligation on the SBF;
- the TDHCA budget is based on a start-up appropriation that is less than the expected on-going expenditure level for the energy-efficiency program; and
- about 700,000 customers participate in the low-income discount program.

The second scenario assumes that:

- the school-funding obligation continues in 2002 at a lower level than the 2001 obligation;
- the TDHCA budget is based on an expected on-going expenditure level for the energy-efficiency program; and
- about 1,400,000 customers participate in the low-income discount program.

As the table illustrates, the SBF revenue would not be adequate under the assumptions in the second scenario.[17] Even if the school-funding and energy-efficiency obligations are lower than projected in scenario 2 for FY 2002, the Commission will probably need to set the SBF fee at the maximum rate allowed, to build up sufficient cash reserves to pay the obligations of the fund as they come due in future years. The Commission will need a reserve of working capital to cover fluctuations in revenues and expenses, to ensure the continuity of the low-income discount program.

Table 5: System Benefit Fund Revenues and Expenses

	Case 1	Case 2
SBF Revenues at 50 cents	116,000,000	39,000,000
SBF Revenues at 65 cents		101,000,000
Total SBF Revenue	116,000,000	150,000,000
School Funding	0	60,000,000
Low Income Energy Efficiency	7,000,000	17,000,000
Low Income Rate Discount	70,000,000	140,000,000
PUC and OPC Funding	13,000,000	13,000,000
Total SBF Expenses	90,000,000	230,000,000
Balance	26,000,000	(80,000,000)

3. Status of SBF

House Bill 3084, 76th Legislature, Reg. Session, prohibited establishing the SBF as a trust fund within the State Treasury. The result of House Bill 3084 is that the SBF currently exists as an account within the general revenue fund without any mechanism to preserve unexpended balances at the end of each fiscal year. This status as a revenue account greatly complicates the administration of the SBF, because any unspent amounts at the end of a state budget biennium would not be

[17] Case 2 shows two different levels for the SBF fee. The maximum allowed by SB 7 is $0.50 until the end of December 2001 and $0.65 for 2002.

available for SBF purposes for the following year. If this situation remains, at the end of each fiscal year the balance in the account will become available for other state uses, and the account will be restated to zero. The Commission would have to delay any expenditures in the new biennium until sufficient new revenues are collected. This delay is particularly troublesome for the rate discount program, because the retail electric providers will expect to be reimbursed on a monthly basis.

In fiscal year 2000 the Commission operated with a special rider that re-appropriated unexpended balances within the biennium. The Commission has requested continuation of its authority to preserve the unexpended balance in the fund within the next biennium, but its rider for this purpose must be re-approved every biennium as a special provision of the agency's appropriations. In the Legislative Recommendation portion of this report, there is a proposal to revise current legislation to provide permanent authority to carry forward any unspent balances in the account to remedy this problem.

4. Issues Arising During the Commission Rulemaking

Several complications came to light during the Commission's rulemaking proceeding on the SBF. Foremost among these is the question of what the Commission should do if SBF funds are inadequate to meet all of the demands upon the fund. Some parties suggested that the Commission set priorities for the four uses of the fund, but there was substantial disagreement over what the order of priority should be. There was also the question of whether the rate discount program should be suspended if there were insufficient funds to reimburse the retail electric providers. The Commission declined to address these issues in the rulemaking proceeding but will address them in the future if they arise.

As mentioned above, there was also disagreement over whether the school funding loss mechanism was a one-time expenditure or an ongoing expenditure out of the fund. This is an issue for which legislative clarification would appear to be more appropriate than Commission resolution.

There was disagreement over how the discount for low-income customers should be determined. Three different interpretations of the statutory language can be reasonably made. One is that the discount should be a standard discounted rate throughout each utility's service territory. Under this interpretation, all retail electric providers that supply electricity to low-income customers would have the same discounted rate. A second option was for the discount to be a 10% discount off each retail electric provider's basic rate. The final option, and the one that the Commission adopted in its rulemaking, was a uniform discount (in cents per kilowatt-hour) in each utility service area. This discount will apply to each retail electric provider's rate, with the discount amount calculated as at least 10% of the affiliated retail electric provider's rate.

F. Emerging Problems

1. Electricity Price Volatility

In 2000 increases in the price of electricity in California and in some of the northeastern states attracted public attention. In California, in particular, a period of very hot weather resulted in price increases in the wholesale market that led to significant increases in the cost of electricity for retail customers in San Diego. Prices rose again in November in the Western market, as a result of high gas prices and increased use of electricity related to heating demand in the Pacific Northwest. The causes for these price spikes are:

- inadequate electric generating resources to serve customers' needs,
- the inability of utility-affiliated retailers to buy power on a long-term or future basis,
- a market structure that does not encourage competition at the retail level, and
- lack of customer response to prices.

The fundamental problem is that new generation projects have not been built in California and neighboring states to keep pace with the growth in demand associated with strong economic growth. Inadequate generation has a predictable result; where demand exceeds supply, prices rise in the wholesale market. The California market rules precluded retail suppliers from buying power on a long-term or future basis, thus preventing them from hedging against price increases in the wholesale market. In addition, because of the lack of competition in retail sales, retailers have not seen the need to protect their customers from the volatile wholesale electricity prices. Finally, customers outside of San Diego are on flat rates and have no incentive to reduce their consumption when wholesale prices are high. Even for San Diego customers, there were no mechanisms to publicize price information, so that they can reduce consumption when prices are high.

Under traditional utility regulation, retail customers are largely isolated from volatility in the wholesale markets, because utilities average rates over time. Utilities typically rely on a mix of generation resources that they own or buy. Some of these are low-cost resources, but generation that is operated or bought during seasonal peaks is typically more expensive. By averaging the costs of all of its resources over a long period, a utility could provide service at stable rates.

In a regulated environment, utilities built generation to meet their expected load plus a reserve margin. The expectation that rates would be set to recover the cost of new generation meant that the decision to build new generation, usually under a regulated planning and licensing process, was not very risky for the utility. In a competitive environment, developers decide to build based on their expectations of earning a profit from the plant, considering the costs, risks and expected revenue. These factors, in turn, are affected by the licensing process for new generation, the ease or difficulty in obtaining an interconnection to the transmission network, and the relevant market rules.

California and some of the Northeastern States have significant impediments to the construction of new generation facilities. In California and New York, it appears that the primary impediment is the state siting process. In New England and Pennsylvania, construction of new generation appears to have been slowed by transmission interconnection rules that require the developers of new generation projects to pay for upgrading the transmission network so that the output from the generation plant can be moved to the markets. In some of the Northeastern states, the natural gas pipeline infrastructure is not adequate to support significant levels of new gas-fired generation, which is the most economical technology in the market today. The bottom line is that in these markets, the supply of generation has not kept up with the increase in demand that has been fueled by strong economic growth. As a result, shortages of power occur, particularly when hot weather increases demand, and price are highly volatile. In addition, California has experienced repeated declarations of emergency (49 event in 2000, compared to four in 1999), the interruption of customers with interruptible service, and several instances of rolling blackouts for firm service customers.

Texas has adopted a different approach on many of these issues. Non-utility generation does not require a state license, other than environmental permits, and new generation facilities are not required to pay for transmission facilities to deliver their power to market. Texas also has a strong gas-delivery infrastructure. Developers have regarded Texas as an attractive place to build new generation facilities, and between September 1995 and August 2000, 4700 MW of new generation capacity has been added. Plants now under construction and expected to be completed by summer 2002 would add 14,000 MW in generating capacity for the period 1995 to 2002. The new capacity is expected to meet the projected demand growth of the strong Texas economy. The ERCOT wholesale market will be a market in which power is traded primarily on a bilateral basis, so that retailers can buy power long-term or buy power for future delivery, reducing their exposure to the risks of higher prices in the wholesale market. ERCOT is also working to develop mechanisms to convey price information to customers and for customers to respond to high prices by reducing their consumption. The combination of these factors should result in adequate electricity in Texas at reasonable prices.

A better supply-demand situation is already evident in Texas. Figure 3 compares energy prices at one of the Western electricity trading hubs, the California-Oregon Border (COB), and ERCOT, during the summer of 2000.[18] The

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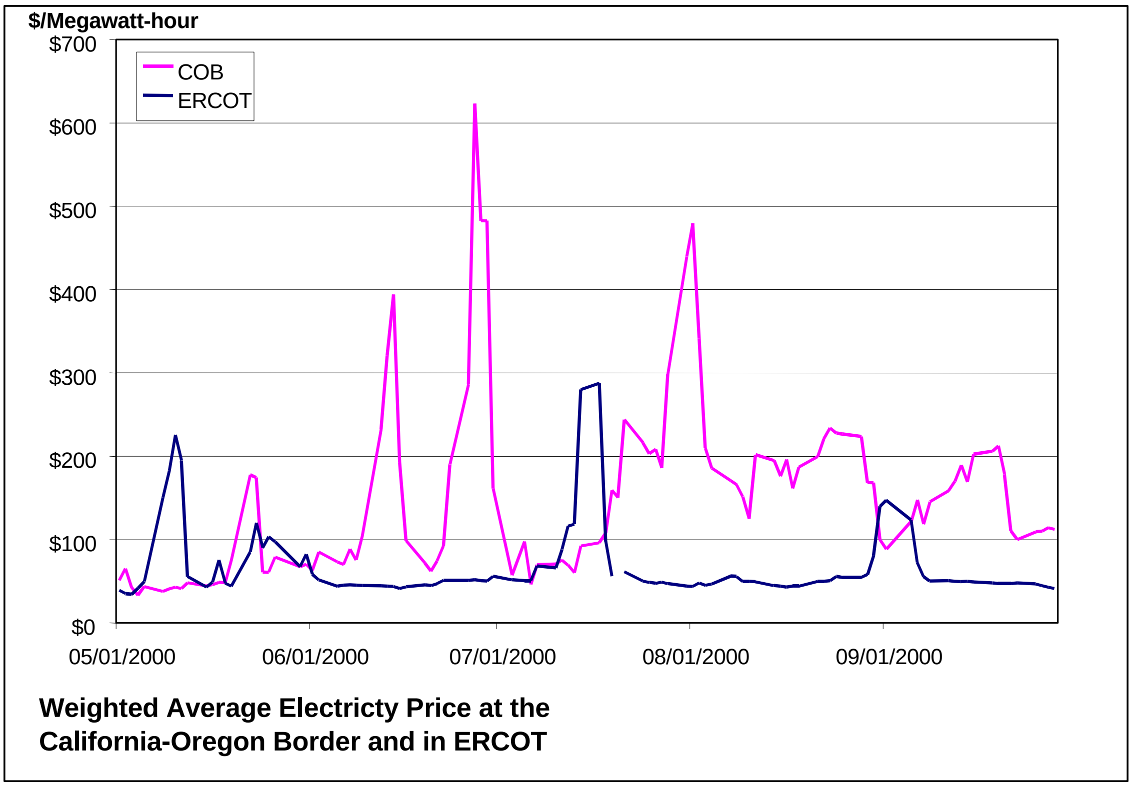
[18] The prices are for a standardized 16-hour block of on-peak power for delivery the next day. COB is a primary import/export point between the Pacific Northwest area and the California ISO. The ERCOT prices are based on comparatively smaller trading volumes in ERCOT.

COB prices show a significant number of price spikes and a sustained higher level of prices from mid-July through the end of September. The median price at COB was \$124/MWh, compared to \$50/MWh in ERCOT. The maximum price at COB was \$624/MWh, compared to \$288/MWh in ERCOT. ERCOT prices were comparatively stable during the summer, despite record heat and a 5% growth in annual peak demand. This stability was due in part to the addition of 3,000 MW of new generation capacity in 2000.

Figure 3: Wholesale Prices in California and Texas, Summer 2000



Source: Based on data from Megawatt Daily, published by Financial Times Energy

Beyond the problems in the wholesale market, California did not encourage retailers to enter the market and compete against each other. New retailers could enter the market, but the rules for the recovery of stranded costs prevented them from offering customers a better price than the price offered by the incumbent utility. For this reason, new retailers had little ability win customers away from the incumbent utility, and there has been little competition at retail. In California, fewer than 2% of customers in the residential sector have switched suppliers in the first two years after the market opened.

In addition, transaction costs for retailers in California and other states are very high. The systems for customer registration and obtaining meter data are decentralized, and the new retailers must communicate with the incumbent utilities through multiple interfaces and under different rules adopted by each utility. These systems were built very rapidly, at a high cost, and without standardization of interfaces. The lack of standardization results in high transaction costs for retailers and reduces their already-low profit margins.

The Texas rules will encourage new competitors to enter the retail market. The price to beat for residential and small commercial customers will freeze the incumbent retailers' rates at a level that the new competitors should be able to undercut. New competitors should be able to enter the market, gain customers, and make a profit. In addition, ERCOT is building common interfaces and centralized systems to support all retailers participating in this market, resulting in lower costs to enter the market.

In California, retail customers were initially under a rate freeze, and a part of their rate was used to recover stranded costs. The rate freeze remains in effect until each utility recovers all of its stranded costs. By July 1999, San Diego Gas & Electric (SDG&E) had recovered all of its stranded costs and was no longer under the rate freeze. SDG&E's retail rate passed through to its customers changes in the wholesale market price. When prices shot up in the wholesale market because of shortages of generation, SDG&E's retail prices also shot up. In a robust retail market competitive retailers should be able to use hedging and forward purchases to offer customers more price certainty. In a competitive retail market, sellers will have to be more responsive to customers' needs for price certainty.

The retail competition model in Texas provides price certainty for residential and small commercial customers for five years. A retail electric provider that is affiliated with an electric utility must offer these customers a fixed "price to beat" when competition begins. This rate is a price floor for three years or until the affiliated retailer loses 40% of its residential and small commercial load. The price to beat remains in effect as a mandatory offer of the affiliated retailer for five years, however. The price to beat will act as a price ceiling for the five-year period. This will give the legislature and the PUC time to assess the market and the extent of competition and make changes in the market rules, if necessary, prior to the removal of this price protection.

While affiliated retailers are not obligated to offer a price to beat to large commercial and industrial customers, the experience in other states suggests that these customers will have a number of ways to insulate themselves from price volatility. They should have substantial leverage in negotiating power supply arrangements with retailers, and many of these customers have the ability to reduce their demand if prices are high. These customers treat electric purchases as a business decision like the many other decisions they make in running their businesses. If price information is conveyed to them in a timely fashion, some business customers will be able to reduce their consumption when prices are high. The Commission will continue to work with ERCOT to develop the infrastructure that will get these customers timely information about prices so that they can make informed decisions. Finally, large customers are expected to be able to enter longer-term contracts that include a mix of services, such as load management, energy efficiency, and risk management, in addition to the supply of electricity.

In part, the volatility in electricity prices is a transition issue. Residential customers have an expectation that prices will be stable and low, and they have not typically made conscious decisions about how much electricity to consume, in response to changes in prices. The regulation of prices over a long period has accustomed customers to stable prices and has not trained them to be aware of prices, and utilities have not developed methods for communicating prices to their customers. In other markets, like the retail market for gasoline, retailers clearly communicate changes in prices, customers are more aware of the prices, and they may change their consumption to respond to changes in prices. One of the challenges of the customer education program is to let customers know that prices may be more volatile, and that in choosing a supplier they need to be concerned about whether the supplier can change the rates, how often it may do so, and the kind of advance notice they can expect.

2. Peak Demand and Adequacy of Capacity for 1998-2000

One of the Commission's concerns in recent years was whether Texas would have adequate electrical generating capacity to meet customers' needs. In a transition to competition, utilities with significant generation assets have been reluctant to invest in new power plants. The Commission has also been reluctant to have utilities invest in new power plants in a competitive wholesale environment. Construction of generating capacity by independent power producers began in earnest after the introduction of wholesale competition in the 1995 amendments of PURA, but the growth in demand initially outpaced the construction of new generation facilities. A hot summer in 1998 resulted in supply interruptions to some customers. To be sure that there was a reliable system and adequate capacity to meet growing demand for electricity in Texas, the Commission closely monitored load forecasts, the construction of new generating capacity, and reserve margins in recent years.

Strong economic growth in Texas in recent years has driven increased consumption of electricity. Demand for electricity grew faster in the late 1990's than in the late 1980's and early 1990s. In particular, utilities serving Central Texas have experienced more than 5% annual growth rates since 1995. Demand for electricity in ERCOT grew at 4.1% per year for the same period. Service areas outside of ERCOT experienced a 1.9% annual growth in peak demand during 1995 through 1999. Overall, Texas experienced a robust 3.8% annual growth in peak demand for electricity during this period. During this period demand grew in ERCOT from about 47,000 Mw to 54,000 Mw, and in the non-ERCOT areas grew from 9,200 Mw to 10,700 Mw.

There were reasonable margins of capacity in 1996 and 1997, so that Commission action was not warranted. In 1998 it became apparent that reserves might fall below 15%, the planning reserve margin that ERCOT utilities have traditionally used. For 1998 through 2000, the Commission has evaluated the adequacy of generating capacity to meet growing demand in Texas by developing independent peak demand forecasts, based on information provided by the utilities and its independent analysis. The Commission estimated potential capacity shortages for the summer periods and directed utilities acquire resources to meet these potential shortfalls.

Looking at 2001 and beyond, the supply in ERCOT appears to be adequate. Table 6 shows the ERCOT ISO's projections of load, resources and reserve margin for 2001 through 2003. (Information is actual for 2000 and projected for 2001 and later.)

Table 6: Projected ERCOT Generating Capacity, Demand and Reserves (in megawatts)

	2000	2001	2002	2003
Generating capacity	65,547	69,947	71,823	72,198
Peak load	57,606	56,664	58,531	60,035
Interruptible load	3,003	3,008	1,607	1,616
Firm summer demand	54,415	53,656	56,906	58,420
Reserve at peak	7,941	16,291	14,917	13,778
Reserve margin	14%	30%	26%	24%

One of the key issues for companies that are building new generation facilities is the ability to interconnect with the transmission network and transmit power to customers. 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 addition, merchant plants have had difficulty obtaining transmission service on non-discriminatory terms. The Commission has addressed interconnection issues in ERCOT in several ways. Initially, the Commission adopted transmission rules that included an obligation to connect new power plants to the transmission network. As issues emerged in connecting power plants owned by companies that were not affiliated with a transmission owner, the Commission modified the rules by clarifying who is responsible for the costs of interconnection, prohibiting utility affiliates from building power plants in the utility's service area, unless the utility had a Commission-approved code of conduct, and increasing the ERCOT ISO's responsibilities for planning related to interconnecting new facilities.

The Commission has also assigned the ISO responsibility for planning the regional transmission network, and the ISO has developed a process for determining regional transmission needs. In its first transmission report, the ISO identified several transmission constraints that could affect the reliability and competitiveness of the wholesale market. Key constraints included transmitting power from the Houston area to the Dallas-Fort Worth area (DFW), transmitting power to and from West Texas, and transmitting power into the Lower Rio Grande Valley (RGV). This planning process resulted in new transmission projects to address these constraints. The Commission granted an amendment of TXU Electric Company's certificate of convenience and necessity (CCN) for a transmission project to alleviate the Houston-DFW constraint, and construction is under way. Central Power & Light Company is also constructing new facilities in the first phase of a project to increase the transmission capacity to the RGV, and the Commission recently approved CCN amendments for additional transmission facilities to alleviate this constraint.

The transmission network is the highway system for the delivery of electricity, and as the economy grows this network needs to grow. The strong growth in the demand for electricity in Texas and the large number of new power plants that have been built or are planned represent a significant challenge to the ISO in planning the transmission network and to the utilities in building new facilities. New transmission facilities will be needed to meet the growth in demand and to permit new generating facilities to deliver their output to customers. Landowners on or near projected transmission rights of way typically do not want new transmission lines near their land. Opposition to new transmission facilities can be particularly acute in urban areas, if the right of way is adjacent to residential areas. PURA establishes a process for the Commission to review new transmission projects and for landowners and other affected persons to contest projects.

Two events during the summer of 1999 demonstrated the importance of projecting peak demand and ensuring that there are adequate resources to meet demand. On July 23rd, Entergy was forced to implement emergency curtailments of retail customers when the demand for electricity on its system exceeded the available power supply. Entergy curtailed service on a rotating basis to more than half a million customers in four states, including more than 94,000 residential, commercial, and industrial customers in southeastern Texas. The curtailments resulted from high temperatures in the Entergy service area, significant loss of Entergy's native generation capacity due to unexpected outages, and a lack of generation available for purchase.

The Commission Staff investigated the incident and concluded that Entergy had underestimated its peak demand requirements, overestimated the reliability of its own generation facilities and resources it had purchased, and failed to properly apply its own emergency response plan and curtailment policies and procedures. The report made 18 recommendations for improvement in the areas of load forecasting, generation planning and maintenance, resource acquisition, generation interconnection, notification to customers and affected public officials, and load shedding procedures. Entergy filed status reports in February 2000 and May 2000 describing the improvements it made in response to the Staff report. By May 2000, Entergy was much better prepared to meet the summer's peak demand than it had been the year before and had few operational problems during the summer of 2000.

The second event affected "interruptible" customers. These are customers who agree to have their service interrupted during periods of high demand, and in return pay a lower price for electricity throughout the year. Typically, they are industrial and large commercial customers. Interruptible load allows a utility to meet its load obligations by reducing the demand for electricity rather than producing or buying more energy. Some interruptible tariffs have a "buy-through" option that allows customers to avoid being interrupted by paying the higher cost for starting up additional generation or buying generation at the current wholesale market price.

In August 1999, some interruptible customers became concerned about the frequency of interruptions to their service and the high cost of buying through to prevent an interruption. In particular, some of TXU Electric's interruptible customers experienced buy-through prices of up to 49¢ per kWh, and some of them were interrupted on two occasions in August without having the option to buy through. Customers were also concerned, because different customers appeared to be subject to different buy-through prices and durations. TXU said that the high buy-through prices and the actual interruptions were due to the lack of generation available in the market.

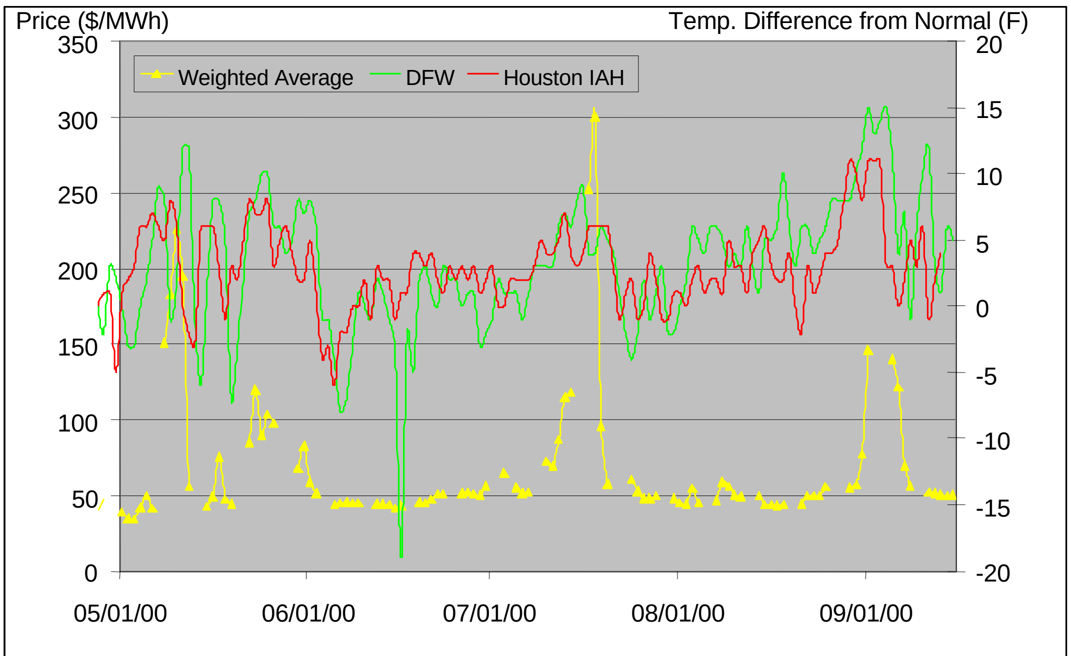
In response to these concerns and to help ensure that interruptible resources would continue to be available, the Commission investigated interruptible electric service for all investor-owned utilities. The Commission Staff found that TXU's interruption procedures were confusing and did not ensure that all customers would pay the same price per kWh for buy-through service. The Staff also surveyed interruptible customers of all the major utilities in the state to determine their satisfaction with interruptible service and to solicit suggestions for improvement. As a result of this investigation, the Commission directed utilities to develop fair, clear, written protocols for interrupting customers and initiating buy-through periods. In addition, TXU met with its interruptible customers on two occasions before the summer of 2000 and developed an alternative pricing option for buy-through costs that would result in all noticed interruptible customers paying the same average buy-through price on an annual basis.

By May 15, 2000, all major utilities had procured adequate generating capacity to serve their peak demands for summer 2000, with adequate reserve margins to address unexpected events and maintain reliability. ERCOT experienced short supply conditions on several days in May when an early heat wave hit before all generating plants were back in service from normal spring maintenance. Reliant Energy HL&P and a few other utilities were forced to interrupt their interruptible customers in order to maintain service to firm-service customers.

The summer of 2000 was unusually hot in Texas, and peak demand rose sharply. On July 19, ERCOT set a new peak demand record of 55,796 MW, but no interruptible customers were interrupted, because there were adequate generation supplies available. In late August and early September, with temperatures ranging from 10 to 15 degrees above normal, many regions of the state broke all-time temperature records. ERCOT set a new peak demand on August 31 at 57,606 MW, which was 5.0% above the 1999 summer peak. Due to the sustained high temperatures and high demand, several utilities were forced to interrupt some of their interruptible customers during this period. In addition, TXU issued a public appeal for voluntary conservation.

Short-term energy prices spiked during the summer of 2000 due to the high temperatures and high demand. Figure 4 compares weighted average prices for short-term energy in ERCOT to temperature deviations above and below normal. It shows that the price spikes (shown in yellow, scale at left) were generally correlated with temperatures that were significantly above normal (shown in red and green, scale at right).[19]

Figure 4: ERCOT Price vs. Temperature



Weighted Average ERCOT Daily Energy Price Versus Temperature Deviations from Normal

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[19] Investigation into Bulk Power Markets, ERCOT (Texas), Federal Energy Regulatory Commission, November 1, 2000.

The number of transactions affected by these price spikes is relatively small, and most customers are served under long-term purchases or capacity that the supplier owns. Electricity markets have typically experienced price volatility, but there were few periods of short duration in which prices in ERCOT were high. Significant capacity additions by new merchant plant owners have begun operation in ERCOT, and additional plants are under construction. These capacity additions should help to assure that electricity will be available at reasonable prices in the next few years. In particular, the capacity additions in 2000 and new construction scheduled for completion in 2001 and 2002 has relieved concerns about shortages of capacity during summer peaks. Figure 6 shows the location of new power plants that have been built in Texas since 1995 or are planned or under construction.

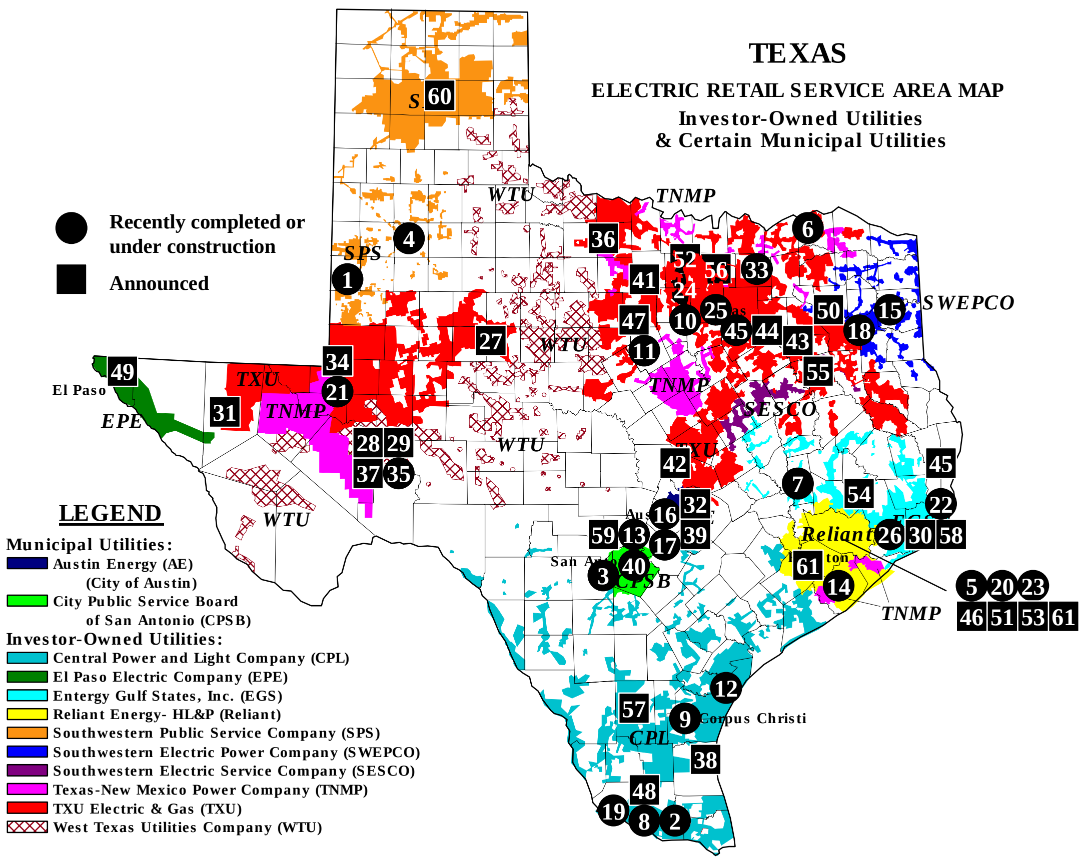

Figure 5: New Power Plants in Texas

3. New Air Emission Standards

The adoption of more stringent air emission standards will affect the cost and reliability of electric service. Most urban areas in Texas do not meet Federal Clean Air Act standards, particularly the ground-level ozone standards, and the Texas Natural Resource Conservation Commission (TNRCC) has adopted State Implementation Plans that impose more stringent air emission standards. These new standards will affect Dallas-Fort Worth (DFW), Beaumont-Port Arthur (BPA) and the Houston-Galveston area. (Areas that are not in compliance with a Federal standard are referred to as non-attainment areas.) The new standards will require emission reductions of nitrogen oxides (NOx) from a number of sources, including electric power plants. The new standards will result in retrofitting power plants with additional pollution controls and the replacement of existing plants with new, cleaner technologies.

The new emission standards will increase the cost of providing electricity. New power plants that are built to meet the new emission standards will have to be equipped with NOx control equipment, which will increase the capital and operating costs of the plants. Retrofitting existing plants will also increase costs. The new emission standards will also impose operating limits on power plants in non-attainment areas. It will be more expensive to build and operate new plants in non-attainment areas than in the rest of the state. Continuing to provide reliable service under the new NOx rules will present challenges in some non-attainment areas, particularly the DFW area. While many new power plants are being built around the State, the current configuration of the ERCOT transmission system limits the amount of power that can be delivered to the DFW area. In order to provide reliable electric service in this area some or all of the power generation facilities within the DFW area must remain in service.

When the electrical requirements of customers in the DFW area are at their peak (typically in the summer), the utilities in the area rely on power-generating units in the DFW non-attainment area and on imports of power from outside the area to meet their customers' needs. This area has experienced strong economic growth in recent years, and the electrical demand has grown with the local economy. The growth in demand is expected to continue.

Senate Bill 7 requires a 50% reduction in NOx emissions and a 25% reduction in sulfur-dioxide emissions (SO_2) for those electric generating facilities that were not required to have an emission permit.[20] The bill allows utilities to recover the cost of new emission-control equipment in their stranded costs, if the new equipment is needed to make the NOx and SO_2 reductions required under SB 7 or the Clean Air Act.[21] The Commission adopted a rule that requires utilities to demonstrate that their plans for meeting the new air emission standards are cost effective. If a plan is cost effective, the utility will be allowed to recover the cost of the emission controls in its stranded costs. Under this rule, the Commission will have to evaluate whether additional pollution controls in parts of East Texas and the DFW, Houston-Galveston, and BPA areas are cost effective.

Beyond the cost issues, the continued reliability of service in the DFW area is a concern, because of the import constraints into the area. The Commission, in

[20] PURA § 39.264.

[21] PURA § 39.263.

conjunction with the ERCOT ISO, has examined electric resource options for this area, including transmission system improvements, new power plants in the area, and energy efficiency. The Commission intends to continue to work to ensure reliable electrical service for the DFW area. The Commission held a conference in the Capitol on November 7, 2000 to examine technologies that can help solve this problem.[22]

G. Federal Legislation

There was an effort to pass comprehensive electric restructuring legislation in the House of Representatives during the 1999-2000 session of Congress. Ultimately, this legislation stalled in committee in the House. The Senate passed a bill that addressed electric reliability, but no action was taken on this bill in the House. Key federal issues are:

- whether to set a date by which states must introduce retail competition;
- consolidation of regional transmission operations;
- clarifying the authority of the Federal government and the States, particularly with respect the FERC's authority to require utilities to join regional transmission organizations;
- reliability;
- customer protections in a retail competition environment;
- authority to address market power;
- environmental issues; and
- modifying existing utility and tax laws to conform to a restructured industry.

The key bill in the House, H.R. 2944 was introduced by Rep. Joe Barton in September 1999 and referred to four different committees to address matters in their jurisdiction. In October 1999 an amended version of the bill passed the Subcommittee on Energy and Power of the Committee on Commerce. This bill addresses many of the issues set out above. It does not, however, require states to implement retail competition by a particular date. Rather, it preserves the authority of the states to require retail competition and the unbundling of transmission and distribution service. One of the most contentious issues in restructuring bills in the previous session of Congress had been a federal mandate for the states to introduce retail competition.

One of the key issues in the Barton Bill is the FERC's authority with respect to transmission service. The bill would also have:

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[22] Presentations from the conference are available on the Commission's web site, http://www.puc.state.tx.us/electric/dfw/dfw.cfm.

- codified the FERC's Order No. 888, in which the FERC required all public utilities under its jurisdiction to provide open-access transmission service;
- extended the obligation to provide such service to utilities that are not regulated by the FERC (such as municipal utilities and electric cooperatives that are financed by the Rural Utilities Service);
- authorized the FERC to require utilities to provide unbundled transmission service in connection with a state retail-access plan;
- authorized the FERC to approve regional transmission organizations;
- authorized the FERC to supervise the nation's reliability organizations; and
- authorized the Federal Trade Commission to adopt customer protection rules for the retail sale of electricity

No bill relating to the regulation of the electric industry was enacted before the last Congress adjourned. These issues are likely to be revived in the next Congress, however.

SECTION III. LEGISLATIVE RECOMMENDATIONS

Section 64 of Senate Bill 7 requires the Public Utility Commission to "study and make recommendations by December 15, 2000, to the legislature for additional legislation that would move to and establish a competitive electric market in accordance with the changes in law made by this Act."[23] The Commission recommends:

- A change to the Gas Utilities Regulatory Act to enhance competition in the electric market.
- A change in the way the System Benefit Fund is administered that to foster the legislative purposes behind the creation of this fund.

The Commission does not recommend any changes or additions to SB 7 or to the Commission's enabling Act[24] that would affect the way retail competition is implemented. The Commission has identified a number of clarifications that could be addressed should the legislature choose to do so. These recommendations and clarifications are discussed below.

A. Recommended Legislation

1. Gas Utilities Regulatory Act

The Commission recommends that a provision be added to the Gas Utilities Regulatory Act[25] in order to prevent the development of a potentially anti-competitive situation involving affiliated natural gas utilities and electric utilities.

During the last few years, two of the largest electric utilities in the state have purchased two of the largest of the natural gas local distribution utilities. As a part of the unbundling required by SB 7, electric utilities will create affiliated retail electric providers, and these two natural gas utilities will be affiliated with retail electric provider. With the start of competition in the electric industry, retail electric providers that have an affiliated gas utility will be in a position to offer combined billing for electric and gas service. It is also possible that the retail electric provider may be able to directly provide gas services by re-branding the gas service under the retail electric provider's name. In either case, the customer, if he

[23] Act of May 27, 1999, 76th Leg., R.S., ch. 405, § 62, 1999 TEX. SESS. LAW 2543.

[24] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-64.158 (Vernon 1998 & Supp. 2000) (PURA).

[25] Gas Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 101.001 *et seq.* (Vernon 1998).

chooses the retail electric provider that is affiliated with the local gas distribution company, will be able to get one bill for both his gas and electric service.

The Commission believes that this may give an unfair advantage to two companies that are incumbent utilities and are affiliated with gas utilities. These companies will create retail electric providers as a part of the unbundling process, and their ability to combine gas and electric billing or service may make it more difficult for other retail electric providers to compete in the retail electric market. One solution to this problem 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 retail electric providers on the same terms and conditions that it does for its affiliated retail electric provider.

2. System Benefit Fund

Senate Bill 7 created the System Benefit Fund (SBF) as a trust fund. Subsequent legislation, House Bill 3084, 76th Legislature, Reg. Session, changed that result, and the SBF was established as an account in the general revenue fund, rather than as a separate trust fund. The SBF will be difficult to administer without the authority to carry forward unspent amounts from fiscal year to fiscal year. The normal rules for appropriated fund accounts require that balances in an account be restated to zero at the end of a fiscal year, and expenses for the new fiscal year would have to be met from SBF revenue in the new fiscal year. Two of the programs that the fund supports involve payments to businesses for benefits that they provide to low-income customers. It will be difficult to ensure the continuity of these programs without the ability to carry revenue forward from fiscal year to fiscal year and biennium to biennium. Therefore, the Commission recommends that the Legislature re-establish the SBF as a separate trust fund. In the alternative, the Commission recommends that the Legislature grant the Commission authority in its appropriations to carry forward unspent SBF revenue.

3. Clarifications

As with any legislation of the magnitude of SB 7, there are a number of ambiguities that have come to light in the process of implementing the legislation. Fortunately, the Commission has for the most part been able to address these issues through decisions and the adoption of rules. If the appropriate committees of the Legislature conclude that electric restructuring issues should be reconsidered, the Commission has identified a few areas where it may be appropriate to clarify SB 7. Those areas are:

Issue 1: Reliability of Electric Service. Included in Section 38.005 of the amended PURA are specific reliability standards for electric utilities. Section 38.005(b) requires the Commission to take enforcement action against a utility if a utility's distribution feeder is among the 10% of worst-performing feeders for that utility two years in a row. The reliability of feeders is measured by the number of and duration of interruptions of service to customers taking service on a feeder, compared with other feeders. This mandate may be appropriate if a utility has a number of feeders that are performing a level significantly below an acceptable standard. It is probably not appropriate, however, if all of a utility's feeders are performing at an acceptable level. Utilities might go to undue effort and expense improving the performance of feeders that are already performing at an acceptable standard, to avoid enforcement action under this section. It may be more appropriate to eliminate the requirement to take action against the utility if a feeder is among the worst-performing feeders in consecutive years and, instead, simply give the Commission the authority to take enforcement action as it deems appropriate. This could be achieved with the following changes:

Sec. 38.005. ELECTRIC SERVICE RELIABILITY MEASURES.

(a) The commission shall implement service quality and reliability standards relating to the delivery of electricity to retail customers by electric utilities and transmission and distribution utilities. The commission by rule shall develop reliability standards, including:

(1) the system-average interruption frequency index (SAIFI);

(2) the system-average interruption duration index (SAIDI);

(3) achievement of average response time for customer service requests or inquiries; or

(4) other standards that the commission finds reasonable and appropriate.

(b) The commission ~~shall~~ **<u>may</u>** take appropriate enforcement action under this section~~, including but not limited to~~ **<u>and shall take action</u>** action against a utility if any feeder ~~with 10 or more customers appears on the utility's list of worst 10 percent performing feeders for any two consecutive years or~~ has had a SAIDI or SAIFI average that is more than 300 percent greater than the system average of all feeders during any two-year period, beginning in the year 2000.

Issue 2: Administration of the System Benefit Fund. The System Benefit Fund was created by SB 7 to carry out various public purposes. Operating it as a fund under the Commission's control will entail certain administrative functions for the Commission, such as approving payments to persons who are authorized to receive revenue from the fund. A similar fund, the Universal Service Fund (USF), has been created by PURA to support telephone service in high-cost areas. In the case of the USF, however, the fund is administered by a neutral, private institution. Private administration is likely to be more efficient and cost-effective, without removing the Commission's responsibility for policy decisions affecting the operation of the fund or for auditing the fund administrator.

The legislative recommendation discussed above, relating to the status of the System Benefit Fund as a general fund, would not be required if legislation were adopted to permit the fund to be administered in the same manner as the USF. Legislation to permit the System Benefit Fund to be administered in the same manner as the USF could be patterned on key provisions of PURA Chapter 57, which deals with the USF.

Issue 3: Priorities under System Benefit Fund. The System Benefit Fund SBF supports four different programs but does not establish a priority among these programs:

1. Compensation for the state and school districts for losses in property values of utilities' assets directly caused by electric industry restructuring;
2. An electric rate discount for low-income customers;
3. A targeted low-income energy-efficiency program administered by the Texas Department of Housing and Community Affairs; and
4. Appropriations to the PUC for customer education programs, and to the PUC and Office of Public Utility Counsel (OPUC) for administrative costs.

If the funds collected by the SBF in a future year were insufficient to support all of the programs at the expected level of expenditures, the Commission would be called upon to resolve the conflict and reduce the funds for one or more of the authorized programs. The revenues into the fund are capped by a rate ceiling in PURA Section 39.903, and the needs of two of the programs will be determined by events that are outside of the control of the Commission and the Legislature. The compensation for losses in property values is dependent on events in the energy markets, and the rate discount is dependent on the number of low-income customers that take advantage of the program. It may be advisable for the legislature to establish priorities for the use of SBF funds, before a shortfall occurs.

Issue 4: Funding for School Tax Losses. It is not entirely clear whether the funding mechanism for revenue losses for school districts requires a single reimbursement or ongoing funding. The source of the uncertainty is Section 39.901 of PURA. Subsection (a) describes how to calculate the loss in revenue and implies that tax losses would occur only once, while subsection (h) establishes the funding mechanism through the 2006-2007 school year. Subsection (a) provides that "the comptroller shall certify to the Texas Education Agency any property wealth reductions, determined by taking the difference between current year and prior year appraisal values attributable to electric utility restructuring."

The introduction of retail competition reduced the value of certain power plants in 1999, the year that SB 7 was enacted. For 1999, the comparison of the current year and prior year (1998) appraisal values showed a significant reduction in value, related to the introduction of competition. If the 2000 values remain the same as the 1999 values, there would not be a reduction in appraised value, and no payment would be due to the Education Agency. If the values remain the same through the 2006-2007 school year, there would be no additional payment into the foundation school fund. The Commission believes that subsection (a) would result in a single payment to the fund for 1999 losses, if property tax values remain stable thereafter. We believe that a future Commission would be likely to interpret the law in this manner, in the absence of additional legislation on this matter.

Issue 5: Performance-Based Rates. In past proceedings some parties have argued that the Commission lacked authority to engage in performance based rate-making or that the Commission's authority to do so is very limited. It would be expedient to avoid such controversy in the future and 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 rate-making. This objective could be achieved with the following changes:

Sec. 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 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. 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 purposes of adjusting revenue.

Issue 6: Definitions. It would appear that apartment complexes, mobile home parks and recreational vehicle parks that sub-meter their electricity would have to register either as aggregators or as retail electric providers by virtue of the definitions of aggregators and retail electric providers in PURA. Also, it would appear persons who provide electric service only to themselves, their employees or their tenants as an incident of the employment or tenancy would also be required to register either as an aggregator or a retail electric provider. Such persons are currently excluded from the definition of electric utility, and as such are not regulated. The Commission does not believe that the Legislature intended to change the special status of any of these entities. Therefore, it may be appropriate to exclude them from the definitions of retail electric provider and aggregator. This objective could be achieved through the following changes:

Sec. 39.352. CERTIFICATION OF RETAIL ELECTRIC PROVIDERS.

(a) After the date of customer choice, a person, including an affiliate of an electric utility, may not provide retail electric service in this state unless the person is certified by the commission as a retail electric provider, in accordance with this section. **A person subject to Chapter 184 is not required to be certified as a retail electric provider, in order to submeter electricity in accordance with that Chapter. A person who furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others, is not required to be certified as an retail electric provider in order to furnish electric service to itself, its employees, or its tenants.**

Sec. 39.353. REGISTRATION OF AGGREGATORS.

(a) A person may not provide aggregation services in the state unless the person is registered with the commission as an aggregator. **A person subject to Chapter 184 is not required to register as an aggregator, in order to submeter electricity in accordance with that Chapter. A person who furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others, is not required to be certified as an retail electric provider in order to furnish electric service to itself, its employees, or its tenants.**

Issue 7: Code of Conduct for Municipal Utilities and Electric Cooperatives. The Commission is charged with adopting code of conduct for cooperatives and municipal utilities pursuant to PURA Section 39.157(e). A code of conduct typically addresses the interactions between affiliated companies or operating units of an entity. Cooperatives and municipal utilities are given the discretion of whether to unbundle their operations and how to do so, that is, whether they create separate business entities (structural unbundling) or simply separate the competitive and non-competitive functions within a single business entity (functional unbundling). See PURA Sections 40.055(a)(2) and 41.055(2). With regard to municipal utilities, the Commission's code of conduct applies only to a structurally unbundled utility. See PURA Section 40.004(4). To minimize the risk of competitive abuses, it may be appropriate to amend PURA to make it clear that the Commission's code of conduct applies, whether the municipal utility unbundles structurally or functionally. This objective could be achieved through the following change in Section 40.004(4):

Sec. 40.004. JURISDICTION OF COMMISSION.

> Except as specifically otherwise provided in this chapter, the commission has jurisdiction over municipally owned utilities only for the following purposes:
>
> (4) to establish a code of conduct as provided by Section 39.157(e) applicable to anticompetitive activities and to affiliate activities limited to structurally unbundled affiliates **or to functionally unbundled units** of municipally owned utilities, subject to Section 40.054;

Issue 8: Aggregators. The provisions of Senate Bill 7 relating to aggregation are not entirely clear. There are three types of aggregators under SB 7: aggregators, municipal aggregators and political subdivision aggregators. Because of the way the sections are structured, it is unclear whether certain provisions set out in the aggregator section, PURA Section 39.353, also apply to municipal and political subdivision aggregators, under PURA Sections 39.354 and 39.3545. Among the provisions in Section 39.353 are the prohibition against aggregators selling or taking title to electricity and the statement that an aggregator is not a retail electric provider. In addition, Section 39.353 requires aggregators to comply with Commission requirements dealing with customer protection.

Senate Bill 7 also added to the Local Government Code (LGC) Sections 303.001 and 303.002, allowing for aggregation. Section 303.001 authorizes political subdivisions, including municipalities, to create political subdivision corporations that can aggregate electricity for the political subdivisions for public facilities. This section is largely consistent with PURA Section 39.3545, except that PURA authorizes persons, in addition to Political Subdivision Corporations to aggregate public facility loads of different political subdivisions. Another anomaly is that LGC Section 303.002 authorizes municipalities to aggregate for their citizens and hire a person or another aggregator to act as administrator, but there is no express provision in PURA that provides for this type of aggregation.

Both Section 303.001 and 303.002 of the Local Government Code are silent on the question of whom the aggregators under these sections may purchase power from. In contrast, the PURA sections state that aggregators of all types will purchase their power from retail electric providers. The PURA sections would prohibit aggregators of all kinds from purchasing from electric cooperatives and municipally owned utilities that have opted for customer choice. The Commission believes that aggregators should have the option of purchasing power from an electric cooperative or a municipally owned utility that has chosen to provide customer choice.

The municipalities have expressed an interest in being able to take title to electricity when they act in the role of an aggregator. Section 303.001 of the Local Government Code expressly states that a political subdivision corporation acting as an aggregator of public load may "purchase" electricity, but Section 303.002 does not address whether a political subdivision may take title when aggregating for its citizens. The Commission believes that a key distinction between a retail electric provider and an aggregator is whether the entity takes title to power, and the Commission has in its rules maintained this distinction. An aggregator taking title to power necessarily calls for the imposition of greater financial qualifications, and it is inconsistent with the view that the aggregator acts on behalf of the purchasers of electricity. By taking title, the aggregator is put in the dual role of acting on behalf of the purchasers and being a vendor of electricity to the purchasers. However, with regard to political subdivisions, their very purpose is to act in their citizens' interest, and some municipalities have entered the electricity business with the purpose of ensuring that electricity is available to their citizens on reasonable terms. If municipalities are allowed to take title to electricity as aggregators, they would function somewhat in the capacity as a retail electric provider, and as such, should be able to purchase power directly from power generation companies. In such circumstances, the municipality will have to arrange for billing of the customers, because power generation companies are prohibited from providing retail service.

The Commission has already been sued over its interpretation of the statutory provisions as reflected in the rule it adopted regarding aggregation. The Commission believes that these statutory provisions can be simplified and be made consistent with the overall model of the market and the role that aggregators and municipalities play, including less need for the Commission oversight to protect and regulate municipalities. To that end the Commission believes that it may be appropriate for the aggregation sections to be modified to achieve a result consistent with the following table. Amendments to achieve this follow the table.

	Person aggregating public entity load	Political Subdivision Corporation aggregating public entity load	Municipality aggregating its citizens	Third party administrator acting for a municipality aggregating the municipality's citizens
Take title to power	No	Yes	Yes	No
PUC's customer protections apply	Yes	No	No	Yes
Can be a retail electric provider	No	Yes. Only "persons" are required to register as a retail electric provider.	Yes. Only "persons" are required to register as a retail electric provider.	No
Can purchase only from a retail electric provider or a cooperative or municipally owned utility providing customer choice	Yes	No	No	No

Sec. 39.353. REGISTRATION OF AGGREGATORS.

(a) A person may not provide aggregation services in the state unless the person is registered with the commission as an aggregator.

(b) In this subchapter, "aggregator" means a person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from retail electric providers **and municipally owned utilities or electric cooperatives that are providing customer choice pursuant to Chapters 40 or 41 of this Code**. Aggregators may not sell or take title to electricity. Retail electric providers are not aggregators.

(c) A person registering under this section shall comply with all customer protection provisions, all disclosure requirements, and all marketing guidelines established by the commission and by this title.

(d) The commission shall establish terms and conditions it determines necessary to regulate the reliability and integrity of aggregators in the state by June 1, 2000.

(e) An aggregator may register any time after September 1, 2000.

(f) The commission shall have up to 60 days to process applications for registration filed by aggregators.

(g) Registration is not required of a customer that is aggregating loads from its own location or facilities.

(h) The commission shall work with the Texas Department of Economic Development to communicate information about opportunities for operation as aggregators to potential new aggregators, including small and historically underutilized businesses.

Sec. 39.354. REGISTRATION OF ~~MUNICIPAL~~ CITIZENS AGGREGATORS.

(a) A ~~municipal~~ **citizens** aggregator may not provide aggregation services in the state unless the ~~municipal~~ **citizens** aggregator registers with the commission.

(b) In this section, "~~municipal~~ citizens aggregator" means **a political subdivision, as that term is defined by Section 303.001(a) of the Local Government Code, that is acting as an aggregator for its citizens pursuant to 303.002 of the Local Government Code or a person acting as an administrator for a political subdivision pursuant to Section 303.002(b) of the Local Government Code**~~. a person authorized by two or more municipal governing bodies to join the bodies into a single purchasing unit to negotiate the purchase of electricity from retail electric providers or aggregation by a municipality under Chapter 303, Local Government Code~~.

(c) A person registered to act as an administrator for a political subdivision under this section shall comply with all customer protection provisions, all disclosure requirements, and all marketing guidelines established by the commission and by this title.

(d) A person registered to act as an administrator for a political subdivision under this section may not sell or take title to electricity and may not be a retail electric provider. Such a person may administer a program in which the political subdivision takes title to the electricity.

(e) The commission shall establish terms and conditions it determines necessary to regulate the reliability and integrity of a person registered to act as an administrator for a political subdivision under this section that is providing service in the state.

(f) A person registered to act as an administrator for a political subdivision under this section may negotiate the purchase of electricity only from retail electric providers and municipally owned utilities or electric cooperatives that are providing customer choice pursuant to Chapters 40 or 41 of this Code.

(~~c~~**g**) A ~~municipal~~ **citizens** aggregator may register any time after September 1~~, 2000~~ **2001**.

Sec. 39.3545. REGISTRATION OF POLITICAL SUBDIVISION AGGREGATORS.

(a) A political subdivision aggregator may not provide aggregation services in the state unless the political subdivision aggregator registers with the commission.

(b) In this section, "political subdivision aggregator" means a ~~person or~~ political subdivision **corporation acting pursuant to Section 303.001 of the Local Government Code or a person** authorized by two or more political subdivision governing bodies to join the bodies into a single purchasing unit or multiple purchasing units to negotiate the purchase of electricity from retail electric providers for the facilities of the aggregated political subdivisions ~~or aggregation by a person or political subdivision under Chapter 303, Local Government Code.~~

(c) A person registered to aggregate the load of political subdivisions under this section shall comply with all customer protection provisions, all disclosure requirements, and all marketing guidelines established by the commission and by this title.

(d) A person registered to aggregate the load of political subdivisions under this section may not sell or take title to electricity and may not be a retail electric provider.

(e) The commission shall establish terms and conditions it determines necessary to regulate the reliability and integrity of a person registered as a political subdivision aggregator under this section that is providing service in the state.

(g) A person registered to aggregate the load of political subdivisions under this section may negotiate the purchase of electricity only from retail electric providers and municipally owned utilities or electric cooperatives that are providing customer choice pursuant to Chapters 40 or 41 of this Code.

(~~c~~**h**) A political subdivision aggregator may register any time after September 1, 2000.

Issue 9: Renewable Energy. Section 39.904(e) and (f) (Goal for Renewable Energy) are duplicative, though worded slightly different. The Commission recommends that subsection (e) be deleted. It is the Commission’s understanding that subsection (f) was intended to be the final version.

APPENDIX: PUC RULEMAKING PROCEEDINGS

ADOPTED RULES—MAJOR RULES

Code of Conduct for Electric Utilities and Affiliates, Project No. 20936, to implement PURA § 39.157

This project established safeguards to govern the interaction between utilities and their affiliates, to prevent market power abuses and cross-subsidization between regulated and unregulated activities. Publication date: August 20, 1999; adoption: November 11, 1999.

Cost Unbundling and Separation of Business Activities, Including Separation of Competitive Energy Services, and Distributed Services, Project No. 21083, to implement PURA §§ 39.051, 39.201

This project developed rules for:

- Separation of competitive energy services from regulated electric utility activities;
- Separation of utilities into a power generation company, a retail electric provider, and a transmission and distribution utility; and
- Standards for determining non-bypassable delivery charges for transmission and distribution utilities, including transmission and distribution rates, estimation of stranded costs, system benefit fund assessment, and nuclear decommissioning charges.

Publication date: September 10, 1999; adoption: December 16, 1999.

Certification of Retail Electric Providers and Registration of Power Generation Companies and Aggregators, Project No. 21082, to implement PURA Chapter 39, Subchapter H

Under this project two separate rules were adopted. One set the standards for registration and operation of aggregators and power generation companies, and the other set the standards for retail electric providers (REPs). Publication date for rule on aggregators and power generation companies: March 17, 2000; adoption: May 31, 2000. Publication date for REP rule: April 28, 2000; adoption: July 12, 2000.

Market Power Mitigation Plans and Generating Capacity Reports, Project No. 21081, to implement PURA §§ 39.155, 39.156, and 39.157

This rule establishes how to calculate market share in the generation market and require reports from the owners of generation. Publication date: April 28, 2000; adoption: August 10, 2000.

Retail Competition Pilot Project, Project No. 21407, to implement PURA § 39.104

This rule establishes the terms for the retail competition pilot project, which begins in June 2001. Publication date: June 16, 2000; adoption: August 10, 2000.

Provider of Last Resort, Project No. 21408, to implement PURA § 39.106

PURA requires that a retail electric provider be designated as the provider of last resort in each service area. This rule defines the terms of service and the procedures for selecting the providers of last resort in each service area. Publication date: July 14, 2000; adoption: October 4, 2000.

Capacity Auction, Project No. 21405, to implement PURA § 39.153

This rule prescribes the terms and conditions for the generation capacity auction required by PURA. Publication date: September 15, 2000; adoption: December 1, 2000.

Customer Protection Rules, Project No. 22255, to implement PURA §§ 17.004, 39.101

This rule implements the customer protection standards in PURA, including protections against slamming and deceptive practices. Publication date: September 1, 2000; adoption: December 7, 2000.

System Benefit Fund Administration, Low-Income Customers, Project Nos. 21187 and 22429, to implement PURA § 39.903

This rule prescribes how the System Benefit Fund will be administered and establishes guidelines for the low-income programs that are supported by the System Benefit Fund. Publication date: September 15, 2000; adoption: December 13, 2000.

Terms and Conditions for Transmission and Distribution Utilities' Retail Distribution Service, Project No. 22187, to implement PURA § 39.203

This project establishes the terms and conditions of the retail distribution service of the investor-owned transmission and distribution utilities in Texas. Establishing statewide uniform terms and conditions of retail distribution service will:

- facilitate a retail electric provider's participation in the electric market,
- preserve the reliability of the distribution system,
- maintain customer safeguards and services, and
- maintain the transmission and distribution utilities' financial integrity.

Publication date: August 4, 2000; adoption: December 13, 2000.

A second rule will establish the terms and conditions of the retail distribution service of the municipal utilities and electric cooperatives that elect to compete in the retail market. Publication date: September 29, 2000; target adoption: February, 2001.

Electric Reliability Standards, Project No. 21076, to implement PURA § 38.005

The purpose of this project was to establish reliability standards for electric utilities. Publication date: September 17, 1999; adoption: December 1, 1999.

Rules for Interconnecting Distributed Generation. Project Nos. 21220 and 22540, to implement PURA § 39.101

The purpose of these projects was to develop rules to ensure that electric customers have access to on-site distributed generation. The rules prescribe terms and conditions for the connection of small power-generation equipment and establish technical requirements to promote the safe and reliable operation of distributed generation. Publication date: September 24, 1999; adoption: November 18, 1999. Modifications published October 6, 2000 and adopted December 13, 2000.

Renewable Energy Mandate, Project No. 20944, to implement PURA § 39.904

The purpose of this project was to develop rules to carry out the mandate in PURA to promote the development of renewable energy technologies. The rule defines the requirements for the purchase of renewable energy by competitive retailers and establishes a renewable energy credit trading program. Publication date: October 22, 1999; adoption: December 16, 1999.

Energy Efficiency Programs, Project No. 21074, to implement PURA § 39.905

The purpose of this project was to develop rules to implement the statutory goal for energy efficiency. The rule requires utilities to fund market-based standard-offer programs and limited, market-transformation programs to reduce statewide energy consumption by at least ten percent of each utility's annual growth in demand by 2004. Publication date: November 12, 1999; adoption: February 24, 2000.

Standards for Recognition of Costs of Environmental Cleanup or Plant Retirement, Project No. 21406, to implement PURA § 39.263

This rule establishes the terms for including in a utility’s stranded costs the environmental costs associated with obtaining permits under the Clean Air Act or complying with new air-emission rules. Publication date: May 12, 2000; adoption: August 24, 2000.

ERCOT Independent Organization Funding, Project No. 21066, to implement PURA § 39.151

This rule permits the ERCOT Independent System Operator to charge a fee for the use of the transmission system to cover the additional funding required to develop the staff and computer systems that are needed for it to carry out the functions of an independent organization. Publication date: July 30, 1999; adoption: September 9, 1999.

Electric Service for Public Retail Customers (GLO Access), Project No. 21073, to implement PURA §§ 35.101 through 35.106

This project developed rules to facilitate the sale of power by the General Land Office to public retail customers. Publication date: August 20, 1999; adoption: September 23, 1999.

Goals for Natural Gas Generating Capacity, Project No. 21072, to implement PURA § 39.9044

The purpose of this project was to develop rules to implement the legislative mandate that 50 percent of the generating capacity installed in Texas after January 1, 2000 use natural gas. The rule establishes the structure for a credit-trading program for gas-fired generating capacity, so that a power generation company, municipally owned utility, or electric cooperative may either directly own or buy generating capacity using natural gas or buy energy credits. However, the credit-trading program will not be implemented until the proportion of new generation capacity in Texas fired by natural gas falls below a trigger level of 55%. Publication date: September 24, 1999; adoption December 1, 1999.

Terms and Conditions for Transmission Service, including Tariffs and Modifications to Existing Transmission Rules, Project No. 21080, to implement PURA § 35.004

This rule modifies current rules to comply with legislative directive to adopt a postage-stamp method for ERCOT transmission pricing. Publication date: October 15, 1999, adoption: December 1, 1999.

PROPOSED RULES—MAJOR RULES

Price to Beat, Project No. 21409, to implement PURA § 39.202

Under PURA the retail electric providers that are affiliated with an electric utility are required to reduce their base rates by 6% on January 1, 2002 for residential and small commercial customers. This rule will prescribe how this requirement is carried out. Publication date: November 10, 2000; target adoption: February 2001.

Code of Conduct for Municipal Utilities and Electric Cooperatives, Project No. 22361, to implement PURA § 39.157

This rule will establish standards to prevent market power abuses and cross-subsidization between regulated and competitive activities of municipal utilities and cooperatives, which are not subject to the code of conduct that has been adopted for electric utilities. Publication date: December 1, 2000; target adoption: February 2001.

ADOPTED RULES—OTHER RULES

Repeal of Integrated Resource Planning Rules, Project No. 21023, to implement repeal of PURA Chapter 34

Form for Securitization of Stranded Costs of Investor-Owned Utilities, Project No. 21046, to implement PURA § 39.201

Securitization of Stranded Costs for River Authorities and Coops, Project No. 21077, to implement PURA §§ 40.003, 41.003

Rule Changes to Conform to Electric Restructuring Act, Project No. 21232, to implement various sections of PURA

Form for Annual Report of Revenues and Expenses, Project No. 21075, to implement PURA § 39.257.