**Paul Hudson** Chairman

Julie Caruthers Parsley Commissioner

Barry T. Smitherman Commissioner

W. Lane Lanford Executive Director



# **Public Utility Commission of Texas**

January 15, 2007

Honorable Members of the Eightieth Texas Legislature:

We are pleased to submit our 2007 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act (PURA).

Retail competition in the Electric Reliability Council of Texas (ERCOT) began on January 1, 2002, and the market has continued to develop and mature in the two years since our previous report. Texas continues to be a leader in North America in implementing competitive electric markets. This report provides an update on the status of the electric markets in Texas, as well as a summary of the Commission's activities during the last biennium relating to retail electric choice and its other electric industry responsibilities under State law. The report concludes with the Commission's legislative recommendations.

Increases in the prices of natural gas and electricity have been the primary challenges for customers and suppliers alike over the course of the last two years. Competitive forces are working to provide competitive prices to customers, but there remain a large number of residential and small commercial customers who have not chosen a competitive supplier and are paying electric rates that are higher than the rates paid by customers who have shopped for another supplier. New competitors have continued to enter the market, and there has been steady growth in the number of retail customers who have exercised the right to choose their electric provider. As of September 2006, over 56% of electricity sold to all customers in areas open to competition was sold by retail electric providers other than the incumbent, as compared to 42% in September 2004. Over one-third of residential customers in competitive areas are now served by providers other than the incumbent, as compared to 18% in September 2004.

The Commission has continued to re-focus its efforts from rate regulation to rule-based regulation, and has enhanced its efforts to monitor and oversee both wholesale and retail electric markets, including enforcement of State statutes and Commission rules. The selection of an Independent Market Monitor will aid the Commission in its oversight of the ERCOT wholesale market, and in identifying opportunities for improvements to market rules and institutions to ensure a well-functioning marketplace. The Commission is also actively implementing key legislative initiatives from the 79<sup>th</sup> Legislature, including rules relating to advanced metering and competitive renewable energy zones.

We look forward to continuing to work with you as you address the energy challenges that consumers in Texas face. If you need additional information about any issues addressed in the report, please do not hesitate to call on us.

Sincerely,

Paul Hudson Chairman

Julie Parsley Commissioner

Barry T. Smitherman

Commissioner

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#### **ACKNOWLEDGEMENTS**

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41

## 2007 SCOPE OF COMPETITION IN ELECTRIC MARKETS IN TEXAS

# TABLE OF CONTENTS

I.	NTRODUCTION AND SUMMARY	7
II.	SUMMARY OF COMMISSION ACTIVITIES FROM 2005 TO 2007 TO REFLECTED OF COMPETITION IN THE ELECTRIC INDUSTRY	ECT CHANGES IN 15
A	Rulemaking Activities	15
	. Major Retail Market Rulemakings	16
	a. Provider of Last Resort	16
	b. Advanced Metering	17
	c. Renewable Energy	17
	d. Retail Electric Competition in Northeast Texas	18
	e. Discount for Low-Income Customers	20
	f. Credit Requirements for Customers Over 65 and Victims of Family Viole	ence 20
	g. Pro Forma Retail Delivery Tariff	21
	. Major wholesale Market Rulemakings	22
	. Other Rulemakings: Interest Rate for True-Op Assets	23
B	Contested Proceedings	25
	. CenterPoint Rate Case	25
	. Texas New-Mexico Power Competition Transition Charge	25
	. First Choice Power Price to Beat Rate Change	25
	AEP Texas Central Securitization	25
	AEP Texas Central Competition Transition Charge	26
	. CPL Retail Energy Price to Beat Rate Change	26
	. WTU Retail Energy Price to Beat Rate Change	27
	. Southwestern Public Service Rate Case	28
	El Paso Electric Rate Case	28
	0. Southwestern Electric Power Company Resource Acquisition 1 Mutual Energy SDD / SWEDCO Margar	29 20
	<ol> <li>Mutual Energy ST / SWEECO Merger</li> <li>Nodel Market Protocols</li> </ol>	29 30
	3 FRCOT Fee Case	30 30
	4. Cap Rock Energy Rate Case	30
ſ	Markat Ovarsight Activities	31
, c	Retail Market Oversight	32
	a Oversight Activities	32
	b. Investigations and Enforcement	32
	. Wholesale Market Oversight	35
	a. Oversight Activities	35
	b. Investigations and Enforcement	35
	c. ERCOT State of the Market Report 2005	37
	d. Independent Market Monitor and Acquisition of IMM Services	38
	. ERCOT Oversight	39
	a. Budget Oversight	39
	b. Operations Oversight	39
Γ	Non-ERCOT Utilities: Market Development Activities	40
1	. Entergy Gulf States, Inc.	41
	a. Qualified Power Region for Entergy	41

Qualified Power Region for Entergy a. b. Entergy Storm Cost Recovery

2. 3.	Southwest Power Pool El Paso Electric Company	42 43
E.	Customer Education Activities	44
1.	Outreach and Public Service Announcements	45
2.	Websites	45
	Answer Center	46
3. 4.	Educational Literature	46
F.	Administration of the System Benefit Fund	46
C II	Flastria Bill Daymont History Databasa	47
Ч.	Electric biii-rayment history Database	4/
III. EF	FECTS OF COMPETITION ON RATES AND SERVICE	50
А.	Effect of Competition on Rates	51
1.	Wholesale Market Prices	51
8	a. Bilateral Market Prices	51
t	b. Balancing Energy Market Prices	52
C	e. Ancillary Service Capacity Market Prices	54
C	l. All-in Price for Electricity	55
e	e. Reserve Margin	57
2.	Retail Market Development and Prices	58
2	Available Choices for Customers	58
ł	b. Residential Rates	59
В.	Switching Activity	64
1.	Residential Customer Switching	65
2	Secondary Voltage Level Commercial and Industrial Customer Switching	67
2.	Primary and Transmission Voltage Level Commercial and Industrial Switching	68
5.	Timary and Transmission voltage Level Commercial and industrial Switching	00
C.	Financial Status of the Texas Electric Industry	69
IV. As	SESSMENT OF OTHER SENATE BILL 7 GOALS AND BENEFITS	74
А.	Customer Protection / Complaint Issues	74
В.	Renewable Energy Mandate	75
C.	Energy Efficiency	78
V. EN	MERGING ISSUES	81
А.	System Hardening	81
В.	Demand Response	81
C.	Calculation of the Low-Income Discount	83
D.	Alternative Transmission Models	84
Е.	Air Permits for Electric Generators	86

88

### VI. LEGISLATIVE RECOMMENDATIONS

А.	Legislative Recommendations	88
1.	Procedural Recommendations	88
a.	Confidentiality of Enforcement Investigations	88
b.	Administrative Penalties	91
2.	Substantive Recommendations	93
a.	Assessment of Generation Market-Share	93
b.	Commission Authority to Address Market Power	96
с.	Securitization of Non-Stranded-Cost True-Up Balances	97
d.	Energy Efficiency Goal	99
e.	Decommissioning Funding for New Nuclear Generation	100
f.	System Benefit Fund Fee	102
g.	Electric System Security	103
h.	Authority of the Commission with Respect to Qualified Scheduling Entities, Munic	cipally
	Owned Utilities, and Electric Cooperatives	105
i.	Repeal of Goal for Natural Gas	107
3.	Potential Actions if Electric Competition is Not Producing Adequate Benefits for	r
	Residential Electric Customers	109
a.	Mandate the Disclosure of the Names of Residential Customers Served by the ARE	P Under
	the PTB at the End of the PTB Period	109
b.	Require Residential Customers to Select a REP After the End of the PTB	110
с.	Increase Customer Education Funding	111
d.	Unbundling in Competitive Markets	111
В.	Legislative Clarifications	112
1.	Procedural Clarification: Commission's Deliberation Concerning Confidential	
	Information	112
2.	Substantive Clarifications	114
a.	Voluntary RECs and the Renewable Energy Mandate	114
b.	Commission's Determination of Competitively Sensitive Information	116
с.	Implementation of Retail Competition in Non-ERCOT Areas	118

#### **APPENDIX: ACRONYMS**

121

# **INDEX OF TABLES**

Table 1: Summary of Stranded Cost and Other True-Up Balances	10
Table 2: Summary of Retail Enforcement Cases	33
Table 3: Summary of Service Quality and Reliability Cases	34
Table 4: Summary of Wholesale Enforcement Cases	36
Table 5: ERCOT Reserve Margin Projection through 2011	57
Table 6: Number of REPs Serving Residential Customers, by Service Territory	59
Table 7: Average Retail Price for Electricity from Selected Gas-dependent Utilities	62
Table 8: Proposed Generation in ERCOT	72
Table 9: Evaluation of Energy Efficiency Programs	79

### **INDEX OF FIGURES**

# I. INTRODUCTION AND SUMMARY

The two years since the Public Utility Commission of Texas' (Commission or PUC) last report to the Legislature on the scope of competition in electric markets have seen many challenges. This report outlines important trends in the industry and the activities that the Commission has undertaken to implement retail and wholesale competition in the sale of electricity. This section of the report highlights important activities and events: high natural gas prices, disruption of service in East Texas resulting from Hurricane Rita, new federal energy legislation, the Commission's completion of stranded cost proceedings for utilities in retail competition, the challenge of ensuring adequate resources to meet customer demand in a competitive environment, the Commission's enhancements of its enforcement efforts, and market development outside of the Electric Reliability Council of Texas (ERCOT).

#### NATURAL GAS PRICE INCREASES AND THEIR IMPACT ON ELECTRICITY PRICES

Dramatic changes in the price of natural gas were key factors affecting the electric industry in Texas in the recent past, because natural gas is an important input in the production of electricity in the competitive wholesale market in Texas. Prices for natural gas escalated sharply in 2005 and fell gradually in 2006. As a result, the price of electricity for most residential customers rose during late 2005 and early 2006. Customers who were willing to shop for competitive retail providers found lower prices for electricity as natural gas prices fell in 2006. However, customers who remained with the incumbent retail providers on the price to beat (PTB) rate continued to pay high electric prices that were set when natural gas prices spiked in late 2005.

The price of electricity in the wholesale market within ERCOT closely correlates to natural gas prices; consequently retail electricity prices for residential customers increased as natural gas prices increased. The incumbent retail electric providers (REPs) were required to offer a partly-regulated rate, the price to beat, for residential and small commercial customers in their home territory. The incumbent REPs could change this rate up to twice a year, based on changes in natural gas prices. The incumbent REPs raised the PTB each year from 2002 through 2005. Most of them raised the PTB twice in both 2004 and 2005.

In August and September of 2005, Hurricanes Katrina and Rita caused significant damage to natural gas-production facilities in the Gulf of Mexico and onshore processing and pipeline infrastructure, resulting in dramatic increases in natural gas prices. The Commission's PTB rule, which is based on PURA §39.202, allows incumbent REPs to change the PTB to incorporate increases and (theoretically) decreases in the 20-day average of 12 months of future natural gas prices, as traded on the New York Mercantile Exchange (NYMEX). The NYMEX average was roughly \$8 per million British thermal units (MMBtu) in July 2005 but escalated sharply in September, reaching a high of \$12 in October 2005. Prices fell over the course of 2006 and reached a low of \$7.42 in October

2006. Spot gas prices, as opposed to the 20-day average of the 12-month forward strip, fell even more dramatically in 2006.

The PTB rates that were in the 8 to 9 cent per kilowatt-hour (kWh) range in early 2002 climbed to a 12 to 13.5 cent range in the summer of 2005, as natural gas prices rose. The PTB rates exceeded 14 cents per kWh in early 2006, following increases that were approved late in 2005. As gas prices fell in 2006, the incumbent REPs did not, for the most part, reduce the PTB rates.<sup>1</sup> During a period of gradually rising energy prices, the PTB allowed the incumbent retail providers to increase retail rates to cover their higher costs of serving customers, and in most periods it allowed new retail providers in the market an opportunity to offer lower prices and induce customers to switch away from the incumbents.

While the PTB generally worked as intended in a market of rising energy prices (with the exception of the fall of 2005, when natural gas prices rose sharply above the level on which the PTB was based), it had a shortcoming in a period when input prices fell significantly. Most customers continued to receive service from the incumbent REPs and pay prices that were above the prices offered by competitive REPs. Competitive REPs offered significant savings compared to the PTB, and provided their customers a bargain relative to price levels for natural gas. For example, regulated residential electric prices in October 2001 were roughly 10.1 cents per kWh in the Dallas area and 10.4 cents per kWh in Houston, at a time when the NYMEX futures average was about \$3.00. In October 2006, with gas futures prices at about \$7.70, competitive suppliers in Dallas and Houston were selling electricity for 12.1 cents per kWh, while incumbent REPs were selling at PTB rates of 15 cents and 16 cents in Dallas and Houston, respectively.

### HURRICANE DAMAGE IN EAST TEXAS

In addition to its impact on gas prices, Hurricane Rita had a major impact on electric service in Southeast Texas. On September 24, 2005, Hurricane Rita made landfall in the Beaumont-Port Arthur area as a strong category 3 hurricane. As it passed through East Texas and Southwest Louisiana, it damaged generation, transmission, and distribution facilities throughout the area. At the outage peak, 1,500,244 electric customers in Texas were without power. The hurricane and related power outages also had a national impact, resulting in damage to refineries; natural gas exploration, processing, and distribution facilities; and the power lines that serve the industrial complexes in the Beaumont-Port Arthur and Lake Charles areas. Together with the damage to facilities in the New Orleans area as a result of Hurricane Katrina, the impact on refinery capacity was substantial.

Utilities in the affected area, with assistance from utility crews from other parts of Texas and the United States, worked diligently to replace damaged lines and poles, repair damaged generation facilities, and restore power to their customers. Power was declared

<sup>&</sup>lt;sup>1</sup> CPL Retail Energy and WTU Retail Energy reduced their PTB rates and the discounted rates that most customers were being charged. First Choice Power's PTB rate was reduced by the Commission as a post-true-up adjustment. For further discussion, see Section II.B.

to be fully restored in Texas on October 8, 2005. During and after the hurricane, several unprecedented events occurred that will make this a storm to remember. Commission Emergency Staff spent more time working on preparing for the storm and assisting the electric and telecommunications restoration efforts than any previous storm in the history of the agency. The State Division of Emergency Management for the first time established a "Tiger Team" of state and federal government staff and utility staff to coordinate the electric service restoration effort. Also, this was the first time that an emergency electrical bulk power transfer was made from ERCOT to the Entergy system, pursuant to an emergency order of the U.S. Department of Energy.

#### FEDERAL LEGISLATION

Among the external events that affect the Texas electric industry is federal legislation. In August 2005, the U.S. Congress enacted the Energy Policy Act of 2005 (EPAct).<sup>2</sup> EPAct included provisions on a number of energy-related topics, including electricity. Among other things, EPAct:

- requires the Federal Energy Regulatory Commission (FERC) to create an electric reliability organization (ERO) to establish and enforce reliability standards for the bulk power system;
- requires state regulators and unregulated utilities to consider new ratemaking standards relating to: (1) net metering, (2) time-based metering and communications (smart metering), and (3) interconnections to the utility network;
- eliminates mandatory purchase and sale requirements with respect to "certain cogeneration facilities" and renewable energy facilities, where these facilities have access to wholesale markets for the sale of electricity; and
- extends the Production Tax Credit, resulting in a tax credit for renewable energy production from projects constructed in 2006 and 2007.

In the 2005 Session, the Legislature adopted amendments to the Public Utility Regulatory Act (PURA) to encourage the installation of advanced metering, and the Commission has initiated a rulemaking proceeding to establish standards for advanced metering relating to the functions of advanced meters and recovery of the costs of the meters. The Commission has also initiated a project to consider the new ratemaking standards.

The provisions of EPAct that are of particular importance to Texas are advanced metering, the renewal of the tax credit for renewable energy projects, and the establishment of a reliability organization. The Production Tax Credit is an important incentive for developers that are considering installing new renewable energy facilities in the United States. The credit amounts to 1.9 cents for each kilowatt-hour of renewable

<sup>&</sup>lt;sup>2</sup> Energy Policy Act of 2005, H.R. 6, 109th Cong. 1st Sess. (2005) (EPAct). The EPAct amended the Federal Power Act (FPA), 16 USC §791a *et seq.* and the Public Utility Regulatory Policies Act, 16 USC §2601 *et seq.* The Production Tax Credit provision amended the Internal Revenue Code, 26 USC §45.

energy produced. EPAct also authorized FERC to create an ERO to establish and enforce reliability standards for the bulk-power system, subject to FERC's review.<sup>3</sup> FERC has adopted a rule outlining the responsibilities of an ERO and has approved the North American Electric Reliability Council (NERC) as the ERO for the United States. The National Energy Board of Canada has also approved NERC as the ERO for Canada. EPAct permits the ERO to delegate to regional entities the authority to propose and enforce regional reliability standards. ERCOT has submitted a proposal to the NERC to serve as the regional entity for reliability matters for the ERCOT region of Texas.

#### STATUS OF TRUE-UP PROCEEDINGS AND SECURITIZATION OF TRANSITION BONDS

In 2004, investor-owned electric utility companies began filing requests for recovery of stranded costs and other true-up balances in accordance with PURA §39.262. The aggregate requested amounts as originally filed by these companies totaled approximately \$7 billion, and of this amount, the Commission ultimately approved recovery for \$3.9 billion. Additionally, prior to the filing of its true-up case, TXU Electric Delivery (TXU ED), the state's largest utility, achieved a global settlement resolving all true-up issues. Under this settlement, TXU ED securitized approximately \$1.3 billion in regulatory assets. Except for Texas-New Mexico Power Company, which has not requested the authority to securitize its approved stranded-cost balance, all the investor-owned electric utilities applying for recovery of positive true-up balances have received Commission authority for and completed the securitization of their stranded costs (though at least one utility may seek legislation to securitize costs of the transition to competition that PURA does not permit to be securitized).<sup>4</sup> The table below summarizes the initial true-up requests made by each company, the Commission-authorized amounts, and the amounts securitized.

	Company's True-Up	Commission	Amount
Company	Request	Decision	Securitized
Texas-New Mexico Power	\$357,135,705	\$110,603,855	
CenterPoint Energy	\$4,249,069,435	\$2,300,888,665	\$1,851,000,000
AEP Texas Central	\$2,406,339,203	\$1,475,933,779	\$1,739,700,000
Totals	\$7,012,544,343	\$3,887,426,299	\$3,590,700,000
TXU Electric Delivery*		\$1,247,413,626	\$1,289,777,000
Totals including TXU settle	ement	\$5,134,839,925	\$4,880,477,000

Table 1: Summary	of Stranded	<b>Cost and Other</b>	<b>True-Up</b>	<b>Balances</b>
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\* TXU achieved a global settlement resolving all true-up issues, and did not file an application for a trueup proceeding.

<sup>3</sup> FPA, 16 USC §824o(a)(2).

<sup>4</sup> The Commission decision in the true-up cases is subject to judicial review, and the true-up decisions have been challenged by the utilities and customer groups.

<u>Note:</u> Amounts include stranded costs and other true-up items such as the capacity auction true-up, retail clawback, and final fuel balances. Amounts under "Commission Decision" include interest through specific dates contemplated in the orders, but do not reflect interest beyond these dates that is included in the securitized amounts.

Prior to the filing of the 2004 true-up cases, Reliant Energy and Central Power & Light securitized regulatory asset amounts of \$749 million and \$797 million, respectively, as allowed by PURA §39.201. These figures, when combined with the securitized amounts listed above, bring the total amount of stranded costs securitized by Texas utility companies to approximately \$6.4 billion. The remaining portions of the authorized true-up balances are being recovered by the companies through non-securitized competition transition charges.<sup>5</sup>

#### MEETING DEMAND FOR ELECTRICITY

In the competitive market, the decision to build new electric generating capacity or to retire existing generation is a financial decision that power generation companies make without regulatory review (other than environmental permits that may be required). During the late 1990's and early years of this decade, significant amounts of new thermal generation was built and put into service in ERCOT. Consequently, in the early years of the current decade the ERCOT region had ample supplies of electric generation. In the recent past, development activity has slowed, in large part because of the abundant generating capacity in the region and the resulting low market prices. Construction of new wind generation has continued, however. The abundant new, efficient natural gas-fired generation, and large quantities of the older gas generation have been retired or mothballed.

While these changes were occurring with respect to production capability, demand for electricity continued to grow, and the projection for the future is continued strong growth in demand. There is a renewed interest among developers in building new generating capacity in ERCOT, but most of the new capacity is not expected to be completed until 2009 or later. A significant portion of the new generating capacity that is contemplated would be coal-fired. With gas prices that are three times higher than in 2001, developers see an opportunity to produce power with coal at a lower cost than gas-fired generation. While coal-fired generation could produce lower-cost electricity for customers in the ERCOT market, there has been public opposition to the coal plants to a large degree based on concerns about emissions in the Dallas-Fort Worth area and the contribution of coal emissions (carbon-dioxide) to global warming. While the market has signaled a need for new capacity, developers face challenges with respect to environmental permitting, financing, construction, and public acceptance, depending on the nature of the capacity that they plan to build.

<sup>&</sup>lt;sup>5</sup> During the 2005 Legislative Session, one company proposed legislation that would have authorized securitization of non-stranded-cost true-up balances. The proposed legislation did not pass. See Section VI.A for further discussion.

ERCOT has forecast that the generation capacity available in 2008 could be slightly below the level required to assure adequate reserve margins and thus adequate service if a critical generator or transmission line "trips off" during peak-load period. Because of the prospect of limited capacity reserves in 2008 and the April 17, 2006 event in which some customers' power was interrupted to maintain reliable service for the remaining customers, ERCOT and the Commission are developing new demand-reduction programs that could be implemented for 2007 and 2008. In addition, ERCOT has requested that the owners of mothballed generation capacity provide updates of their plans. Approximately 1,900 megawatts (MW) of mothballed capacity is expected to come back into service for the peak seasons in 2007 and 2008.<sup>6</sup> As of the writing of this report, it seems likely that, as a result, ERCOT will project that the 2008 reserve margin will slightly exceed the 12.5% target when it issues its *Report on the Capacity, Demand, and Reserves in the ERCOT Region* in June 2007. However, current capacity and demand projections raise significant concern about reserve margins beyond 2008, unless new generation resources that have been announced are completed.

In areas outside of ERCOT, where retail supply of electricity currently remains regulated, growth in demand is also occurring, and utilities in these areas have announced plans to buy power from other suppliers or build new generating facilities to meet their customers' needs. The decision to build new facilities requires Commission approval, through an amendment to the utility's Certificate of Convenience and Necessity.

#### MARKET POWER AND RESOURCE ADEQUACY RULE

In 2006, the Commission adopted new wholesale market rules pertaining to market power and resource adequacy. One of the rules provides a definition of "market power" to help the Independent Market Monitor and Commission identify companies that have market power and to provide more certainty to market participants as to how the Commission will deal with market power abuse in the wholesale market. The rule identifies certain behavior that will be considered market power abuse, allows generating companies to file voluntary market mitigation plans to ensure compliance with the rule, and provides a safe-harbor for very small generators.

At the same time it adopted the market power rule, the Commission adopted a rule relating to resource adequacy in the ERCOT power region, to help ensure that the construction of new electric generating facilities will keep pace with the growth in demand for electricity (as described on the preceding page). Unlike other organized electric markets (PJM, for example) that pay generators a capacity payment to provide incentives for generators to build new plants or keep existing plants in operation, the Commission elected to maintain ERCOT as an energy-only market. Therefore, in ERCOT generators are paid only when they sell energy. They are not paid (by customers) simply for building plants or keeping them in operation. The resource

<sup>&</sup>lt;sup>6</sup> TXU Corporation and Topaz Power Group recently advised ERCOT that they will return some of their respective mothballed units, totaling approximately 1,900 MW, to service. See Section III.A.1 for discussion of reserve margins and mothballed units.

adequacy rule modifies existing offer caps and eliminates certain other price mitigation mechanisms to allow market prices to rise when generation is in short supply, in order to provide incentives for construction of new generation facilities. The offer cap that has been \$1,000 per megawatt-hour (MWh) would rise over a three-year period to \$3,000 per MWh. The rule also provides for publishing entity-specific information on offers into ERCOT real-time energy and ancillary services markets within 30 to 90 days after the information was compiled. Furthermore, information identifying the highest bid during each interval, and the entity making that bid, would be required to be posted within 48 hours after the information was collected. The resource adequacy and market power rules were adopted together, so that price increases related to scarcity would be permitted but price increases resulting from the exercise of market power could be identified and addressed.

The disclosure portions of the rule were challenged by several market participants contending that the Commission lacked authority to require disclosure of the information under PURA and the Texas Public Information Act (TPIA).<sup>7</sup> The City of Garland also challenged the disclosure provisions, claiming that they contravened the TPIA. On September 29, 2006, the Court of Appeals issued Orders in both cases staying implementation of the disclosure requirements of PUC SUBST. R. 25.505(f)(3) pending further orders from the Court. A ruling on the merits is expected in 2007.

#### MARKET MONITORING AND ENFORCEMENT

The Commission has taken steps to enhance its monitoring of the wholesale and retail electric markets and its enforcement of Commission rules to ensure that consumers receive the full benefits of competitive markets and reliable, high-quality electric service. Pursuant to legislation enacted in 2005, the Commission has adopted rules for an Independent Market Monitor of the ERCOT wholesale market and has hired a company to provide the monitoring services. It has also increased its level of enforcement activity in both the retail and wholesale markets and sought administrative penalties against utilities for deficiencies in the provision of service.

Legislation enacted in 2005 also gave the Commission the authority to assess administrative penalties of up to \$25,000 for violations of its rules (in place of the prior \$5,000 limit), and directed the Commission to adopt a classification system for assessing penalties. The Commission adopted rules in 2006 to allow penalties up to the maximum amount authorized by statute and to specify a system of classification of violations. The Commission has a range of options to compel compliance with its rules and uses informal discussions with a market participant, warning letters, and administrative penalties to address violations. It typically also seeks restitution for those who have been harmed by the violation. Higher administrative penalties are expected to provide stronger motivation to companies to comply with Commission rules and to settle penalty cases more quickly when violations do occur.

<sup>&</sup>lt;sup>7</sup> See Constellation Energy Commodities Group, Inc. v. Public Utility Commission of Texas, No. 03-06-00552-CV, (Tex. App. – Austin); City of Garland v. Public Utility Commission of Texas, No. 03-06-00571-CV, (Tex. App. – Austin) (both cases are direct appeals of a competition rule).

Prior to the transition to competitive electricity markets in Texas, regulation of the electric industry was performed primarily through rate-setting proceedings, where the Commission would examine costs, revenues, service quality, and the regulated utilities' compliance with Commission rules and Texas statutes. As the industry has transitioned to competitive markets, rule-based regulation and monitoring of the markets has become more important, with the objective of detecting and preventing fraudulent, unfair, misleading, deceptive, and anticompetitive business practices that might disrupt the competitive market and harm customers.

The Commission continues to make significant progress towards the implementation of a consistent and cohesive agency-wide approach to market monitoring and enforcement of Commission rules and Texas statutes. Since 2002, the Commission has assessed over \$9 million in administrative penalties and approved nearly \$70 million in restitution to customers or other market participants. The Commission has addressed matters such as slamming, improper disconnection, market manipulation, deceptive marketing, and service quality issues through its enforcement processes. Agency resources are increasingly being focused on market monitoring and enforcement efforts while still retaining sufficient resources to perform traditional rate regulation of transmission and distribution utilities and integrated utilities that operate outside of the ERCOT region.

The Commission anticipates that market monitoring and enforcement will continue to be a major focus of the agency in the future. Pursuant to recent federal legislation, the Commission expects that reliability of the electrical network will be a more important enforcement issue and that the Commission will have a role in reliability enforcement in ERCOT. The Commission continues to examine more effective and timely ways to bring enforcement proceedings against companies that violate Commission rules and harm customers or the competitive market.

#### MARKET DEVELOPMENT OUTSIDE OF ERCOT

While retail competition remains in effect in ERCOT, retail competition has been delayed in the non-ERCOT regions of Texas either by legislative mandate or by order of the Commission. These areas remain, for now, regulated, primarily because of the lack of independent operation of the transmission systems in those areas and the lack of organized wholesale markets, which are necessary prerequisites for retail competition. Entergy Gulf States is scheduled to file a proceeding by January 1, 2007, to determine the power region that is appropriate for it. The Commission has adopted rules that delayed retail competition for the El Paso Electric, Southwestern Electric Power Company, and Southwestern Public Service Company service areas, and has outlined the steps necessary for competition in these areas. The Commission continues to regulate the rates of utilities that have not opened to retail competition, and will continue to work with these utilities as milestones for the implementation of robust retail competition are explored and undertaken.

# II. SUMMARY OF COMMISSION ACTIVITIES FROM 2005 TO 2007 TO REFLECT CHANGES IN THE SCOPE OF COMPETITION IN THE ELECTRIC INDUSTRY

The Commission continues to develop rules, policies, rates, and procedures for the competitive retail electric market in Texas, and to address the areas and functions that remain subject to Commission rate regulation. Recent tasks have also been related to the implementation of legislation from the 79<sup>th</sup> Legislative Session. These activities include:

- the refinement of rules to implement Senate Bill 7;<sup>8</sup>
- the review of rates for wholesale transmission service, the review of rates for electric retail delivery service, and the review of rates for regulated utilities that have not introduced retail competition;
- the review and approval of price to beat fuel factor adjustments pursuant to PURA §39.202, until the expiration of the price to beat on January 1, 2007;
- the approval of the ERCOT Administrative Fee;
- consideration and approval of protocols to implement the ERCOT nodal market;
- enforcement and oversight activities, including assessing administrative penalties for violations of PURA and Commission rules, and the establishment of an Independent Market Monitor to aid the Commission in monitoring the ERCOT wholesale market;
- continued efforts to explore how to implement retail competition in the non-ERCOT areas of Texas;
- customer education activities;
- the certification of REPs and the registration of aggregators; and
- the administration of the System Benefit Fund (SBF).

# A. **RULEMAKING ACTIVITIES**

During 2005 and 2006, the Commission continued to implement new rules and refine existing rules to facilitate the successful operation of the competitive market. In some cases, the Commission has discovered a need for additional rules not originally developed prior to the opening of the retail market in 2002. In other cases, the Commission has found a need to revise previously adopted rules in order to provide additional clarity or to better conform the rules to the reality of the competitive market.

<sup>&</sup>lt;sup>8</sup> Rules are adopted or amended in accordance with the Administrative Procedures Act, TEX. GOV'T CODE ANN. §§2001.001-.902 (Vernon 2000 & Supp. 2005).

The statutory process for adopting new rules or amending existing rules requires an agency to publish a proposed rule in the *Texas Register* for public comments, consider the comments it receives, and then adopt a rule with reasoned justification for its adoption, including a response to the public comments. In most of the rulemakings relating to retail and wholesale competition, the Commission has provided significant additional opportunities for interested persons to exchange views and suggestions through the publication of questions for comment and public workshops prior to the development of the proposed rule. While this process often takes a longer time than the standard APA process, the additional opportunities for interested persons to participate in the development of rules has resulted in better proposed rules, and increased confidence in the rules by those who will have to comply with them.

#### 1. Major Retail Market Rulemakings

#### a. Provider of Last Resort

The Commission amended its rule relating to the Provider of Last Resort (POLR) to reduce the risks associated with providing POLR service and to allow REPs providing POLR service to offer more attractive rates to customers who would otherwise receive service at the POLR rate.<sup>9</sup> Under these amendments, POLR service is available only to customers requesting the service and customers whose REP defaults.<sup>10</sup> The rule also changes the process used to select the POLRs, increases the number of REPs serving as POLRs, and changes the methodology to price POLR service. The amended rule divides POLR customers into four categories: residential, small non-residential, medium nonresidential, and large non-residential. All REPs must file information to determine their eligibility to serve as a POLR. After the eligibility list is created, REPs may volunteer to serve a specified amount of POLR customers. In the event there are more POLR customers than volunteer POLR REPs have volunteered to serve, there shall be five nonvolunteering POLRs that will assume the responsibility of serving the remaining POLR customers. As POLR service must be provided without much advance notice, the POLR rate must reflect the inherent risk to the REP, therefore the POLR rate formula was modified to fluctuate with the Market Clearing Price of Energy (MCPE). POLR service is envisioned as a temporary service, thus the rule amendments allow POLRs to charge POLR customers a rate less than the official POLR rate, and to market to and enroll POLR customers in non-POLR, market-based competitive products and services.

These rule revisions were intended to address concerns over the POLR selection process and the potential risk to a single POLR. The new process attempts to avoid burdening

<sup>&</sup>lt;sup>9</sup> Evaluation of Default Service for Residential Customers and Review of Rules Relating to the Price to Beat and Provider of Last Resort, Project No. 31416, Order Adopting Amendment to §25.43 (Jul. 10, 2006).

<sup>&</sup>lt;sup>10</sup> Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39.106(c) and (g) (Vernon 1998 & Supp. 2005) (PURA).

any REP by allowing REPs to volunteer to serve POLR customers. In the event a REP must serve as a non-volunteer POLR, the five REPs most capable of serving POLR customers will share the responsibility. The introduction of the MCPE-based POLR rate formula should insulate the POLRs from serving POLR customers at a financial loss. Allowing the POLRs to market other products to POLR customers and enroll them in market-based competitive products and services should ensure that POLR service remains temporary in nature for customers whose selected REP defaults.

#### b. Advanced Metering

House Bill 2129, passed during the 79<sup>th</sup> Legislative Session, allows utilities to fund the deployment of advanced meters through a surcharge. The Commission has initiated a rulemaking process to address issues relating to the effective deployment of advanced metering and the recovery of the costs of deployment. The rule, if adopted, should provide regulatory certainty for utilities and better information and uniformity for REPs.<sup>11</sup> In a competitive environment, the benefits of advanced metering are spread among the market participants, but the transmission and distribution utility (TDU) would make decisions on deployment. One of the objectives of the rule is to ensure that the benefits of advanced metering are realized not only by utilities, but also by REPs and customers.

The proposed rule contains "minimum functionality" criteria that the utilities must meet in their advanced metering deployment. The purpose of the minimum functionality is to ensure that the best combination of operating capabilities, consumer benefits, and operating reliability are realized. Utilities would be able to decide what technology is best for their systems, as long as the advanced metering system meets the functionality and other standards prescribed in the rule. This includes the use of a standard interface and data format for meter data so that REPs can make product offerings to customers with locations in multiple TDU service areas, without having to customize either the product offering or operational processes.

House Bill 2129 directed the Commission to submit a report to the Legislature on advanced metering and recommend any necessary policy changes to combat barriers to the implementation of advanced metering. The Commission submitted a report on September 29, 2006, and the report stated that the Commission has not identified barriers to implementing advanced metering.

### c. Renewable Energy

A new rule adopted by the Commission in December 2006 establishes a procedure to designate competitive renewable energy zones (CREZs) in Texas.<sup>12</sup> The concept of

<sup>&</sup>lt;sup>11</sup> PUC Rulemaking Relating to Advanced Metering, Project No. 31418 (pending).

<sup>&</sup>lt;sup>12</sup> *PUC Rulemaking Related to Renewable Energy Goal Amendments*, Project No. 31852, Order Adopting New §25.174 (Dec. 15, 2006).

CREZs was formulated by the 79<sup>th</sup> Legislature in Senate Bill 20 to ensure that sufficient transmission infrastructure exists to meet the state's goal for renewable energy as set forth in PURA §39.904 and to improve the coordination of the construction of transmission facilities and renewable generation facilities. Under the new rule, proposed line upgrades serving a CREZ are deemed to be used and useful to the utility in providing service to the public. This will expedite the process by which new transmission projects serving renewable energy resources may be approved by the Commission, and reduce the risk that a utility's construction of transmission to serve a potential wind zone might be challenged as not providing benefit to the utility's customers. The identification of CREZs will also reduce the development risks for renewable generation.

Senate Bill 7 established the state's goal for renewable energy in 1999 but made no special provisions for transmission to interconnect renewable resources. The rapid development of wind power in West Texas since 2001 has shown that wind farms can be built more quickly than transmission, however. This timing difference poses a dilemma for planning: it is difficult to know whether a new line will be needed if the generation facilities do not yet exist, but a wind farm is difficult to finance if there is no certainty that sufficient transmission will be available to deliver generated electricity. Senate Bill 20 is an effort to solve this dilemma by authorizing the Commission to identify an area with sufficient renewable energy potential, and pre-designate the need for transmission facilities serving the area even if no specific renewable generation projects exist or are under construction. The designation of CREZs in regions with developable renewable resources would be partially based on financial commitments of wind project developers desirous of building in the zone.

The rule does not designate any CREZ. Rather, it establishes the procedure for the contested dockets in which designations will be made. Considering the magnitude of capital investment involved and the complexity of the transmission analysis, designating the CREZ in a contested case proceeding is preferable to making the designations in a rulemaking. The rule requires ERCOT to study the wind energy production potential statewide, establishes criteria for designating CREZs, ties financial commitments by renewable generation developers to the transmission licensing process, and establishes transmission rights for companies that develop renewable generation in a CREZ.

The Commission anticipates issuing its first order in late spring 2007. Once the CREZ order is entered, the affected transmission utilities will have one year to prepare their applications for Certificates of Convenience and Necessity (CCNs). The CCN proceeding is expected to take six months, after which construction would take another one to two years. As a result, transmission from the first group of CREZs is expected to be available by 2010 or 2011. PURA §39.904(a) requires a total of 5,880 MW of renewable capacity by 2015, with a target of 10,000 MW by 2025.

### d. Retail Electric Competition in Northeast Texas

The Commission adopted a new rule to address the readiness of the Southwestern Electric Power Company (SWEPCO) service area in Texas and the Southwest Power

#### Chapter II. Summary of Commission Activities from 2005 to 2007 to Reflect Changes in the Scope of Competition in the Electric Industry

Pool portion of the AEP Texas North Company (AEP-TNC-SPP) service area in Texas to offer retail competition.<sup>13</sup> In this rule, the Commission determined that the power region including SWEPCO and AEP-TNC-SPP remains unable to offer fair competition and reliable service to all customer classes under competition; therefore retail customer choice must be further delayed until January 1, 2011, at the earliest.

PURA §39.103 authorizes the Commission to delay the initiation of retail customer choice in any power region if the Commission determines that the power region is unable to offer fair competition and reliable service to all retail customer classes. Customer choice in the SWEPCO and AEP-TNC-SPP areas had previously been delayed by order of the Commission until January 1, 2007, at the earliest.<sup>14</sup>

In addition to delaying competition until at least January 1, 2011, the new rule defines the process and the sequence of events for the introduction of retail competition in these areas of Texas, and establishes the steps that must occur in order for an area to be able to provide fair competition and reliable service to all customer classes. These steps include:

- approval of a Regional Transmission Organization (RTO) by FERC for the power region containing the utilities' service areas and the commencement of independent operation of the transmission network;
- the continuation of pilot projects;
- the filing of a plan for the development of retail market protocols to facilitate retail competition, and a plan for the development of a balancing energy market, a market for ancillary services, and a market-based congestion management system for the wholesale market in the region in which the RTO operates;
- the implementation of a seams agreement with adjacent power regions to reduce barriers to entry and facilitate competition;
- the filing and review of a transition to competition plan, approval of a business separation plan or amendments to the business separation plan, and setting of unbundled transmission and distribution rates;
- certification of a qualified power region pursuant to PURA §39.152; and
- the setting of price to beat rates for the utilities' service areas.

The rule will give certainty to the customers and potential customers in SWEPCO and AEP-TNC-SPP regarding their electricity service. The process, sequence of events, and steps set forth in the rule will help to ensure that competition develops in these service areas only when the appropriate infrastructure is in place in a manner that ensures that the area can offer fair competition and reliable service to all customer classes.

<sup>&</sup>lt;sup>13</sup> *PUC Rulemaking Proceeding Relating to Retail Electric Competition in Northeast Texas*, Project No. 32104, Order Adopting New §25.422 (Aug. 28, 2006).

<sup>&</sup>lt;sup>14</sup> Southwest Power Pool Market Readiness Implementation Docket, Docket No. 24869, Final Order (May 9, 2003).

#### e. Discount for Low-Income Customers

The 79th Legislature amended PURA §39.903, relating to System Benefit Fund, which governs the electric rate reduction program, to allow the Commission to set the rate discount at an amount lower than 10%, and appropriated no funds for the program for the FY 2006 to 2007 biennium. In 2006, the Commission adopted amendments to the rule to recognize the prospect of varying levels of appropriations.<sup>15</sup> The amended rule specifies that the rate reduction would be up to 20%, rather than 10% to 20%, of the price to beat or standard offer package. The rule was also amended to reflect benefits for low-income customers in the Commission's Customer Protection Rules, which provide that a customer who qualifies for the rate reduction program may pay a deposit in excess of \$50 in two installments, and that a customer who was receiving the low-income discount also qualifies for a waiver of late fees. To continue these benefits to the extent possible, the rule was amended to ensure that the deposit installment benefit would be provided by REPs even when sufficient funds to provide a discount and administer an eligibility list have not been appropriated. The rule was also amended to set forth provisions for voluntary low-income programs to be administered by REPs.

The amended rule reflects amendments to the statute, accounts for potential variations in appropriations or lack of appropriations, and ensures that customers can receive benefits related to the rate reduction program when the rate reduction program is not in effect and the state is not funding an eligibility list.<sup>16</sup>

### f. Credit Requirements for Customers Over 65 and Victims of Family Violence

The Commission adopted two changes to PUC SUBST. R. 25.478, relating to Credit Requirements and Deposits, to make it easier for victims of family violence and the elderly to establish credit to initiate electric service. First, the rule was amended to expand the list of entities that may certify a person as a victim of family violence.<sup>17</sup> Local law enforcement personnel, the Office of a Texas District Attorney or County Attorney, the Office of Attorney General, and grantees of the Texas Equal Access to Justice Foundation may now designate a customer as a victim of family violence to demonstrate satisfactory credit for establishing electric service.

<sup>&</sup>lt;sup>15</sup> *PUC Rulemaking Relating to the Discount for Low-Income Electric Customers*, Project No. 31417, Order Adopting Amendments to §§25.454, 25.475, 25.478 (Mar. 3, 2006).

<sup>&</sup>lt;sup>16</sup> The amendments to PURA §39.903 enacted by the 79<sup>th</sup> Legislature in Senate Bill 408 included a provision for one-time assistance to permit low-income customers to avoid disconnection if they have not paid their electric bill. The Commission did not adopt amendments to address this issue, because there were no appropriations for the low-income discount program for the current biennium.

<sup>&</sup>lt;sup>17</sup> PUC Rulemaking to Amend §25.478, Relating to the Establishment of Satisfactory Credit for Victims of Family Violence, Project No. 30047, Order Adopting Amendment to §25.478 (Apr. 5, 2005).

The applicability of the rule was also expanded so that customers 65 years or older meeting specific criteria could satisfy any competitive REP's credit and deposit requirements, rather than just the requirements of affiliated REPs and POLRs.<sup>18</sup>

#### g. Pro Forma Retail Delivery Tariff

One of the rules adopted early in the implementation of retail competition was a standard tariff for delivery service, which established the terms and conditions for utilities to deliver power to homes and businesses in the competitive electric market. In 2005, the Commission amended the standard tariff to improve the operation of the retail market.<sup>19</sup> The key improvements were the adoption of performance standards for key retail transactions that affect customers and REPs, so that, for example, customers have a clear expectation that power will be established when they move in to a new home or business location within two business days of the request for service. The revised tariff also reflects changes in market practices that have occurred since the rule was first adopted, and creates a greater degree of uniformity among the TDUs that are subject to the rule. Some of the changes in the amended rule, in particular the performance standards for transactions, cannot be implemented without computer system changes. Thus, some of the amendments will not take effect until July 2007.

As a result of the new rule amendments, TDUs are required to perform actual readings of electric meters on a monthly basis. Estimated readings related to issues other than customer denial of access are limited to three consecutive estimates. Customers that repeatedly fail to provide access to the TDU to read the meter will be required to choose a permanent solution to resolve the access problem. Additionally, TDUs will be required to have a system in place to verify meter readings, in order to detect readings that are likely to be incorrect (such as zero usage and very high usage).

Consistent with new provisions of law relating to broadband communications services offered over electric transmission and distribution facilities, the amended tariff specifies that the operation of Broadband over Powerline (BPL) shall not interfere with or diminish the reliability of the electric delivery system. The tariff also provides that if a disruption of electric delivery service occurs, the TDU is required to prioritize restoration of delivery service ahead of BPL-related systems.

<sup>&</sup>lt;sup>18</sup> PUC Rulemaking Relating to Amendment of Credit and Deposit Requirements for Victims of Family Violence and Low-Income Elderly Customers, Project No. 31853, Order Adopting Amendment to §25.478 (Jun. 12, 2006).

<sup>&</sup>lt;sup>19</sup> *PUC Rulemaking to Amend §25.214 and Pro Forma Retail Delivery Tariff*, Project No. 29637, Order Adopting Amendment to §25.214 (Apr. 20, 2006).

#### 2. Major Wholesale Market Rulemakings

In 2006, the Commission adopted new wholesale market rules pertaining to market power and resource adequacy.<sup>20</sup> PUC SUBST. R. 25.504, relating to Wholesale Market Power in the Electric Reliability Council of Texas Power Region, provides a definition of the term "market power" that is consistent with the definition commonly used by the courts. This will provide more certainty to market participants as to how the Commission will apply the provisions of its previously adopted PUC SUBST. R. 25.503, relating to Oversight of Wholesale Market Participants. It will also assist the Independent Market Monitor (IMM) in performing its duties.<sup>21</sup> The rule identifies certain behaviors, such as predatory pricing, withholding of production, precluding entry, and collusion, which will be considered market power abuse. However, it provides an opportunity for generators to file voluntary market mitigation plans to ensure compliance with the market power rule. It also provides an exemption from allegations of ERCOT-wide market power for generators controlling less than 5% of the total installed generating capacity. The Commission anticipates that its ability to identify and address market power abuses will be enhanced by this rule.

At the same time it adopted the market power rule, the Commission adopted PUC SUBST. R. 25.505, relating to Resource Adequacy in the Electric Reliability Council of Texas Power Region, to help ensure that the construction of new electric generating facilities will keep pace with the growth in demand for electricity. The rule incorporates the existing energy-only market design in ERCOT and provides incentives for new construction of generation and increased demand response by market participants by allowing wholesale market prices to rise in response to scarcity of resources. It was important to develop the resource adequacy rule in conjunction with the market power rule so that price increases could result from true scarcity but not from the exercise of market power.

The rule phases in higher offer caps in the wholesale market over a three-year period. The current offer cap of \$1,000 per MW or MWh is sufficient to encourage new baseload generation, but the Commission determined that higher offer caps, increasing to \$3,000 in 2009 when the ERCOT nodal market opens, are needed to encourage new peaking generation and more price-responsive load. However, if the actual market prices in any year lead to revenues that are more than twice the annualized costs for a new peaking generator on a \$ per MW basis, the rule provides for lowering the offer caps to a fuel-indexed price for the remainder of the year. Thus, the rule will allow higher prices

<sup>&</sup>lt;sup>20</sup> PUC Rulemaking on Wholesale Electric Market Power and Resource Adequacy in the ERCOT Power Region, Project No. 31972, Order Adopting Amendment to §25.502, New §25.504, and New §25.505 (Aug. 23, 2006). This project was created in October 2005 by combining PUC Rulemaking on the Definition of Wholesale Electric Market Power in ERCOT, Project No. 29042, and PUC Rulemaking Concerning Planning Reserve Margin Requirements, Project No. 24255.

<sup>&</sup>lt;sup>21</sup> PUC Rulemaking to Address an Independent Market Monitor for the Wholesale Electric Market in ERCOT, Project No. 31111, Order Adopting New §25.365 (Apr. 20, 2006).

that certain types of resources need to recover their costs, but it will protect loads from sustained high prices during periods when generation reserve margins are low.

A key element of the resource adequacy rule is public disclosure of information, and the rule addressed both the disclosure of information concerning resource needs and information concerning prices in the wholesale markets administered by ERCOT. Pursuant to the rule, ERCOT would periodically publish aggregated pricing data that market participants can use to plan their operations and facilities better on a short, medium, and long-term basis. ERCOT would also publish disaggregated pricing data 30 days after the day for which it is submitted. Furthermore, ERCOT would publish information identifying the highest bid during each interval, and the entity making that bid, within 48 hours after the information was collected. Although the Commission and the IMM already have access to pricing data, public disclosure would deter generation companies from offering unreasonably high prices and permit broader scrutiny of questionable prices by other market participants and the general public.

The disclosure portions of the rule were challenged by several market participants contending that the Commission lacked authority to require disclosure under PURA and the TPIA.<sup>22</sup> The City of Garland also challenged the disclosure provisions, claiming that they contravened the TPIA. On September 29, 2006, the Court of Appeals issued Orders in both cases staying implementation of the disclosure requirements of PUC SUBST. R. 25.505(f)(3) pending further orders from the Court. A ruling on the merits is expected in 2007.

The Commission discontinued the use of the Modified Competitive Solution Method (MCSM), which was previously implemented by the Commission to protect the market from hockey-stick bidding in circumstances that did not reflect true scarcity of supply. The Commission concluded that the resource adequacy and market power rules, in combination with the new nodal market to be implemented in ERCOT in 2009, make the MCSM unnecessary. In light of the challenge against the disclosure portions of the resource adequacy rule, the Commission has opened a project to consider whether to reinstitute the MCSM and return the offer caps to \$1,000 per MW or MWh.<sup>23</sup>

### 3. Other Rulemakings: Interest Rate for True-Up Assets

One of the objectives of the original retail competition law was to permit utilities to recover the stranded costs that resulted from the introduction of competition. The law included provisions that allowed utilities to "securitize" their stranded costs, that is, to sell bonds that would be funded by the revenue the utilities would receive for the stranded costs. The bonds were expected to bear an interest rate that would be substantially lower than the normal utility rate of return on capital assets, the weighted

<sup>&</sup>lt;sup>22</sup> Constellation Energy Commodities Group, Inc., No. 03-06-00552-CV; City of Garland, No. 03-06-00571-CV.

<sup>&</sup>lt;sup>23</sup> PUC Rulemaking Proceeding to Amend §25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas, Project No. 33490 (pending).

average cost of capital (WACC). This expectation has proved correct, and utilities have sold securitization bonds at rates that are roughly half their pre-tax WACC.

Some of the amounts that the utilities were permitted to recover following the true-up of stranded costs were not permitted to be securitized, and in November 2005, the Commission opened a project to require utilities to use a lower interest rate than their WACC on these amounts.<sup>24</sup> In June 2006, the Commission adopted a rule amendment to establish a methodology for calculating the interest rate on true-up balances that a utility is permitted to recover through rates, but has not securitized. The effect of the amendment is to lower the interest rate from a utility's WACC to a rate generally based on the utility's cost of debt. This change results in reduced carrying costs charged to customers.

The Commission initially adopted PUC SUBST. R. 25.263 in December 2001. The rule established that carrying charges on utilities' true-up balances were to be calculated at the WACC rate authorized by the Commission in the rate proceedings conducted pursuant to PURA §39.201 (the unbundled cost of service proceedings). The rule specified that the WACC rate was to be applied to a utility's authorized true-up balance until the utility issued transition bonds to securitize the balance, and that the *entirety* of a utility's *net* true-up balance would be eligible for securitization and the associated lower-cost financing advantages.

Immediately after the true-up rule's adoption, several utility companies filed appeals of certain parts of the rule. The Third Court of Appeals ultimately determined that certain components of the true-up balance (such as the final fuel balance, the retail clawback, and the capacity auction true-up balance) did not meet the definition of stranded costs, and thus were not eligible for securitization. Since these costs could not be securitized, the rule that was in effect at that time required that carrying charges be at the utilities' WACC.

The Commission's basis for adoption of the rule amendment was that the risk of not recovering unsecuritized true-up balances is less than the average risk of recovering all the utility's cash flows.

<sup>&</sup>lt;sup>24</sup> *PUC Rulemaking Proceeding to Amend PUC SUBST. R. 25.263 Relating to True-up Proceeding,* Project No. 32008, Order Adopting Amendment to §25.263 (Jun. 30, 2006).

# **B. CONTESTED PROCEEDINGS**

#### 1. CenterPoint Rate Case

The Commission initiated a review of the rates of CenterPoint Energy Houston Electric, LLC (CenterPoint) in late 2005. In July 2006, after several months of negotiations, parties filed a settlement resolving the investigation of CenterPoint's rates and the remand of HL&P's 2001 rate unbundling (UCOS) case. The settlement provides for a decrease in CenterPoint's annual revenue requirement of about \$58 million, and an increase of \$10 million for energy efficiency programs. CenterPoint will also spend \$10 million annually for financial assistance to low-income customers. In settlement of the UCOS case, CenterPoint will reduce retail and wholesale rates an additional \$8 million per year for four years. The agreement freezes CenterPoint's rates until at least June 30, 2010, with certain exceptions.<sup>25</sup>

#### 2. Texas New-Mexico Power Competition Transition Charge

In November 2005, Texas-New Mexico Power Company (TNMP) filed its case to finalize and recover its stranded costs in the approximate amount of \$126 million. In April 2006, the Commission's Order on Certified Question effectively reduced the claim by \$4.3 million. Thereafter, a non-unanimous settlement (NUS) was entered into which further reduced the claim by \$5.5 million. The Commission adopted the NUS and entered a Final Order in November 2006.<sup>26</sup>

### **3.** First Choice Power Price to Beat Rate Change

First Choice Power, the affiliated REP of TNMP, filed an application to adjust its price to beat base rate. The application was consolidated with TNMP's CTC case because the adjustment of the price to beat base rate depended on the Final Order in TNMP's CTC case. The NUS and Final Order discussed above also covered First Choice's case.<sup>27</sup>

### 4. **AEP Texas Central Securitization**

In March 2006, AEP Texas Central Company (AEP TCC) filed an application to securitize qualified costs in the amount of \$1,804,070,165. In May 2006, the

<sup>&</sup>lt;sup>25</sup> Petition by Commission Staff for a Review of the Rates of CenterPoint Energy Houston Electric, LLC Pursuant to PURA §36.151, Docket No. 32093, Final Order (Sep. 5, 2006).

<sup>&</sup>lt;sup>26</sup> Application of Texas-New Mexico Power Company to Establish a Competition Transition Charge Pursuant to PUC SUBST. R. 25.263(n), Docket No. 31994, Final Order (Nov. 2, 2006).

<sup>&</sup>lt;sup>27</sup> Application of First Choice Power Special Purpose, LP to Adjust its Price to Beat Base Rates Pursuant to PURA §39.202 and PUC SUBST. R. 25.41(g)(3), Docket No. 32109, Final Order (Nov. 2, 2006).

Commission approved a settlement allowing AEP TCC to recover approximately \$83 million less than the request. The Commission issued a Financing Order on June 21, 2006, incorporating the terms of the settlement and authorizing AEP TCC to issue transition bonds in the amount of \$1,696,620,385.<sup>28</sup> The transition bonds were issued in October 2006 for a total amount of \$1,793,700,000.

### 5. AEP Texas Central Competition Transition Charge

In May 2006, AEP TCC filed an application for a CTC to address true-up balances not eligible for securitization.<sup>29</sup> Unlike CTCs approved for other utilities, AEP TCC's proposed CTC is a credit, rather than a surcharge, to customers in the amount of \$474,706,475. However, because of a federal injunction affecting a portion of the final fuel balance and a recent IRS pronouncement affecting certain tax balances, the Commission has severed from this docket the issue of the proper disposition of the affected CTC amounts (approximately \$117,000,000).

### 6. CPL Retail Energy Price to Beat Rate Change

The Commission adopted a settlement agreement with CPL Retail Energy (CPL) to permit CPL to revise its price to beat rates pursuant to PURA §39.202(k) in a manner that differed from the Commission's price to beat rule, PUC SUBST. R. 25.41(g)(3).<sup>30</sup> Under the settlement, CPL adjusted its price to beat rate through a discounted fuel factor to customers taking price to beat service as of June 30, 2006. Key customer benefits from the settlement agreement were that customers were guaranteed a reduction in rates during the summer months, customers were provided rate stability and discounts through the end of 2006, and low-income customers received additional discounts.

For the residential customer class, for the months of July through September 30, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$9.31 per MMBtu, which is 18.7% below the fuel factor approved in late 2005 in Docket No. 31842.<sup>31</sup> For the months of October though December 31, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.90 per MMBtu, which is 4.4% below the fuel factor approved in Docket No. 31842.

<sup>&</sup>lt;sup>28</sup> Application of AEP Texas Central Company for a Financing Order, Docket No. 32475, Financing Order (Jun. 21, 2006).

<sup>&</sup>lt;sup>29</sup> Application of AEP Texas Central Company for a Competitive Transition Charge Pursuant to PUC SUBST. R. 25.263(n), Docket No. 32758, Notice of Approval (Dec. 1, 2006).

<sup>&</sup>lt;sup>30</sup> Petition of CPL Retail Energy LP to Implement Settlement Regarding Revisions to Price to Beat Rates Pursuant to PURA §39.202(k) and PUC SUBST. R. 25.41(g)(3), Docket No. 32694, Final Order (May 26, 2006).

<sup>&</sup>lt;sup>31</sup> Application of CPL Retail Energy LP to Increase Price to Beat Fuel Factors, Docket No. 31842, Final Order (Nov. 2, 2005).

#### Chapter II. Summary of Commission Activities from 2005 to 2007 to Reflect Changes in the Scope of Competition in the Electric Industry

For the small commercial customer class, for the months of July through September 30, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.418 per MMBtu, which is 9.1% below the fuel factor approved in Docket No. 31842. For the months of October though December 31, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.90 per MMBtu, which is 4.4% below the fuel factor approved in Docket No. 31842.

As part of the settlement agreement, CPL provided its eligible low-income, residential customers an additional 10% discount for the month of May 2006, and an additional 5% low-income discount for the months of June through December 31, 2006. Additionally, CPL agreed to provide \$500,000 to the Texas Association of Community Action Agencies to augment funding for member agencies that provide low-income energy assistance and support. Also, CPL and its affiliates, WTU Retail Energy and Direct Energy, agreed to collectively spend \$150,000 from funds already dedicated for low-income assistance to implement an energy efficiency program targeted to low-income customers served by those companies. CPL's price to beat base rates under the settlement were still subject to change concurrently with the implementation of each true-up related change to non-bypassable charges of AEP TCC.

### 7. WTU Retail Energy Price to Beat Rate Change

The Commission adopted a settlement agreement with WTU Retail Energy (WTU) to permit WTU to revise its price to beat rates pursuant to PURA §39.202(k) in a manner that differed from the Commission's price to beat rule, PUC SUBST. R. 25.41(g)(3).<sup>32</sup> Under the settlement, WTU adjusted its price to beat rate through a discounted fuel factor to customers taking price to beat service as of June 30, 2006. Key customer benefits from the settlement agreement were that customers were guaranteed a reduction in rates during the summer months, customers were provided rate stability and discounts through the end of 2006, and low-income customers received additional discounts.

For the residential customer class, for the months of July through September 30, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$9.31 per MMBtu, which is 18.7% below the fuel factor approved in late 2005 in Docket No. 31843.<sup>33</sup> For the months of October though December 31, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.90 per MMBtu, which is 4.4% below the fuel factor approved in Docket No. 31843.

For the small commercial customer class, for the months of July through September 30, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.418 per MMBtu, which is 9.1% below the fuel factor approved in Docket No.

<sup>&</sup>lt;sup>32</sup> Petition of WTU Retail Energy LP to Implement Settlement Regarding Revisions to Price to Beat Rates Pursuant to PURA §39.202(k) and PUC SUBST. R. 25.41(g)(3), Docket No. 32693, Final Order (May 26, 2006).

<sup>&</sup>lt;sup>33</sup> Application of WTU Retail Energy LP to Increase Price to Beat Fuel Factors, Docket No. 31843, Final Order (Nov. 2, 2005).

31843. For the months of October though December 31, 2006, the discounted fuel factor was based upon an imputed natural gas price no higher than \$10.90 per MMBtu, which is 4.4% below the fuel factor approved in Docket No. 31843.

As part of the settlement agreement, WTU provided its eligible low-income, residential customers an additional 10% discount for the month of May 2006, and an additional 5% low-income discount for the months of June through December 31, 2006. Additionally, WTU and its affiliates, CPL Retail Energy and Direct Energy, agreed to collectively spend \$150,000 from funds already dedicated for low-income assistance to implement an energy efficiency program targeted to low-income customers served by those companies. WTU's price to beat base rates under the settlement were still subject to change concurrently with the implementation of each true-up related change to non-bypassable charges of AEP Texas North Company (AEP TNC).

### 8. Southwestern Public Service Rate Case

On May 31, 2006, Southwestern Public Service Company (SPS) filed a statement of intent to increase rates for electric service in its service area in the Panhandle South Plains.<sup>34</sup> SPS's most recent base rate case was decided by the Commission in 1993. As part of its application, SPS seeks to increase its base revenues by \$47.9 million, a 6% increase. SPS also proposes to consolidate several smaller rate classes, increase its depreciation rates, increase its line loss factors, account for changes in municipal franchise fees, update its service rules and regulations, and make other changes in its accounting for fuel expenses, purchased power capacity, and wholesale interruptible power. If SPS's request is approved, an average residential customer using 800 kWh of energy per month would see a bill increase of \$5.18 per month, or approximately 7.4%. SPS is also seeking to recover under-collected fuel expenses in the amount of approximately \$138 million that it incurred during the period from January 1, 2004, through December 31, 2005. SPS's request has been referred to the State Office of Administrative Hearings (SOAH) for an evidentiary hearing. A final Commission decision is not expected until spring or early summer of 2007.

# 9. El Paso Electric Rate Case

El Paso Electric Company (EPE) and the City of El Paso filed a request to allow EPE to retain 75% of off-system electric sales margins and revenues from providing wholesale transmission service, and freeze electric base rates through June 2010.<sup>35</sup> The Commission has previously allowed EPE to retain either 75% or 50% of the off-system

<sup>&</sup>lt;sup>34</sup> Application of Southwestern Public Service Company for (1) Authority to Change Rates, (2) Reconciliation of its Fuel Costs for 2004 and 2005, (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors, and (4) Related Relief, Docket No. 32766 (pending).

<sup>&</sup>lt;sup>35</sup> Joint Petition of El Paso Electric Company and the City of El Paso for Approval of Fuel-Related Provisions of Rate Agreement, Docket No. 32289 (pending).

margins and wholesale transmission revenue. Commission Staff and Border Steel, Inc., a large industrial customer, have signed a NUS with EPE and the City. This case is currently pending before the Commission, with a decision expected in early 2007.

#### 10. Southwestern Electric Power Company Resource Acquisition

In January 2006, SWEPCO requested that the Commission approve the acquisition of power-related resources in order to continue providing reliable service while meeting customer demand.<sup>36</sup> SWEPCO is seeking to add up to 1,600 MW of long-term resources to its generation supply over the years 2008 to 2011. In the initial request, SWEPCO indicated that it would accept proposals for a self-build option, purchase of existing generation resources, or long-term purchased power contracts. Subsequent to the filing, SWEPCO determined it would build a peaking generating plant, an intermediate plant, and a baseload facility. The 332 MW peaking plant would be built in Arkansas and be operational in 2008. The 500 MW intermediate plant would be built in Louisiana for operation in 2010. The base load plant would also be built in Louisiana and would commence operations in 2011. SWEPCO has filed for a CCN from the Commission for the peaking and intermediate plants.

### 11. Mutual Energy SPP / SWEPCO Merger

In May 2006, AEP TNC, Mutual Energy SWEPCO, LP d/b/a Mutual Energy SPP (ME SPP), and SWEPCO filed for regulatory approval to transfer customers, facilities, and certificated service area located in the Southwest Power Pool (SPP) from ME SPP and AEP TNC to SWEPCO.<sup>37</sup> The transaction arises out of a unique situation resulting from the restructuring of the electric utility industry in Texas. Although full retail competition commenced on January 1, 2002, for the ERCOT portion of AEP TNC's service territory (previously West Texas Utilities Company), competition was delayed for those West Texas Utilities customers located in the SPP region. These ME SPP customers have received bundled service under regulated rates approved by the Commission. This application is a response to concerns regarding the level of rates in the area and the need for a longer-term solution for these customers.

Under the proposal, the obligation to serve customers in the ME SPP area would be transferred from ME SPP to SWEPCO. The customers would receive service from SWEPCO and pay bundled rates like other customers outside of ERCOT. The outcome of the filing is pending at the Commission.

<sup>&</sup>lt;sup>36</sup> Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization; Sale, Transfer, or Merger Public Interest Findings; and/or Approval of Purchased Power Supply Agreements, Docket No. 32318 (pending).

<sup>&</sup>lt;sup>37</sup> Application of AEP Texas North Company, Mutual Energy SWEPCO LP, and Southwestern Electric Power Company for Approval to Transfer Facilities and Customer Service Obligation, and Approval of Tariffs, Docket No. 32672 (pending).

#### 12. Nodal Market Protocols

The nodal market Protocols are ERCOT's primary rules for the nodal market that is scheduled to begin no later than January 1, 2009. ERCOT submitted the nodal Protocols for Commission approval on September 23, 2005. ERCOT submitted the Protocols well in advance of the start of the market so that it and market participants would have time to develop computer systems that complied with the Protocols and to prepare to operate their companies in compliance with those Protocols. A number of changes to the Protocols were proposed. The Commission ordered further consideration of some issues, for possible future revisions to the Protocols. However, in an Order issued on April 5, 2006, the Commission approved the Protocols with only limited changes that preserve the tax-exempt status of municipalities, cooperatives, and other entities that issue tax-exempt bonds.<sup>38</sup>

### **13.** ERCOT Fee Case

In October 2005, ERCOT filed an application requesting that the administrative fee for the ERCOT system remain at the \$0.42 per MWh level set by the Commission in 2004. Under this fee, ERCOT estimated that it would recover an annual revenue requirement of \$129.4 million, consisting of \$124.9 million in projected operating expenses for 2006, \$3.0 million for establishment of the IMM, and \$1.5 million for additional debt service. ERCOT's application was accompanied by two reports required by the Commission in the prior proceeding: (1) a workforce analysis performed by Jefferson Associates, and (2) a review of ERCOT's employee compensation and benefits by Mercer Human Resources Consulting. In its Order of May 15, 2006, the Commission reduced ERCOT's revenue requirement by \$858,000 to remove unreasonable and unnecessary items from the budget and established the administrative fee at the level of \$0.4171 per MWh.<sup>39</sup> The Commission created an additional project to further review employee compensation and benefit levels, which it completed following a public workshop on June 8, 2006.<sup>40</sup>

### 14. Cap Rock Energy Rate Case

In October 2003, the Commission initiated a review of the rates of Cap Rock Energy Corporation (Cap Rock) to determine whether Cap Rock's then-current rates were just and reasonable. Following a lengthy hearing on this matter, the Commission issued its Order on Rehearing in November 2005, reducing Cap Rock's authorized revenue by

<sup>&</sup>lt;sup>38</sup> Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC SUBST. R. 25.501, Docket No. 31540, Final Order (Apr. 5, 2006).

<sup>&</sup>lt;sup>39</sup> Application of the Electric Reliability Council of Texas for Approval of the ERCOT System Administration Fee, Docket No. 31824, Final Order (May 15, 2006).

<sup>&</sup>lt;sup>40</sup> *PUC Proceeding to Review Employee Compensation Levels of the Electric Reliability Council of Texas*, Project No. 32494, Memorandum to Conclude Project (Jun. 8, 2006).

approximately \$1.7 million or 2.578%.<sup>41</sup> To address questions concerning the quality of Cap Rock's management and potential conflicts of interest, the Commission ordered that an independent management audit of Cap Rock be conducted at Cap Rock's expense. The management audit is expected to commence by the end of 2006.

# C. MARKET OVERSIGHT ACTIVITIES

Market monitoring of both wholesale and retail electric markets is an important function of the Commission that is intended to ensure that customers receive the full benefits of competitive markets.

Market monitoring directly involves the Commission, ERCOT, and the Commission's IMM. Market monitoring indirectly involves companies that are buyers and sellers in the wholesale market, retail customers, and REPs, all of whom provide information to the Commission about conduct or practices they observe in the wholesale and retail markets. The focuses of these monitoring activities are to evaluate the effectiveness of the market rules and identify ways to improve them, and to identify violations of rules and take actions that will improve the level of compliance. Some of the recent rulemaking proceedings discussed in Section II.A of this report were initiated to improve market rules.

When violations or possible violations of market rules are discovered, the Commission and its Staff have several options available to compel compliance.<sup>42</sup> The range of options for minor violations includes holding informal discussions with the market participant to obtain redress for the violation or a commitment to comply with the rule in the future, or the issuance of a warning letter. In more serious cases, the Commission can issue a Notice of Violation (NOV) seeking an administrative penalty and compensation for those who have been harmed by the violation.

Many of the enforcement cases are settled, either before the NOV is issued or before a hearing is held. If a market participant contests the penalty, it has the right to a hearing before a judge from SOAH, and a decision by the Commission.

<sup>&</sup>lt;sup>41</sup> Petition of PUC Staff to Inquire into the Reasonableness of Rates and Services of Cap Rock Energy Corporation, Docket No. 28813, Order on Rehearing (Nov. 10, 2005).

<sup>&</sup>lt;sup>42</sup> The Commission also seeks to ensure compliance with other rules and has, for example, issued Notices of Violation to assess penalties against electric utilities for violations of the Commission's service quality standards.

### 1. Retail Market Oversight

#### a. Oversight Activities

The Commission's Retail Market Oversight (RMO) section of the Electric Industry Oversight Division and the Legal Division coordinate activities regarding oversight of the retail electric market. Oversight of the retail electric market is performed in several ways:

- ongoing review of the operation of the market as measured through the number of providers in the market, retail prices in the market, switching rates, and other competitive market indicators;
- ongoing review of the appropriateness and completeness of Commission rules governing the operation of the retail market, including customer protections;
- detection and investigation of possible violations of Commission rules, PURA, or the ERCOT Protocols through planned compliance monitoring, ad hoc compliance monitoring, evaluation of reports of violations by other market participants, and the informal complaint process; and
- informal and formal attempts to compel compliance when potential violations are discovered.

#### b. Investigations and Enforcement

During the period from January 2005 to December 2006, the Commission assessed over \$520,000 in administrative penalties for violations of Commission rules or Texas statutes related to retail electric service and ordered over \$2.5 million in refunds to customers as part of the resolution of investigations or enforcement actions. Additionally, at the time of the writing of this report, four additional enforcement actions were pending with recommended penalties of over \$435,000 and the recommended revocation of the license of a REP.

The table below provides a summary of retail enforcement cases brought by the Executive Director since January 2005. In addition to the cases listed here, Commission Staff conducted a number of other investigations where no violation or a minor instance of non-compliance was discovered or where the company properly remedied an inadvertent violation after being served with a notice of the violation.

Date Finalized	Docket	Company	Penalty or Recommended Penalty	Refund (if applicable)	Alleged Violation
n/a	28369 / 28371	Republic Power	\$25,650		Failure to respond to customer complaints.
2/22/2005	30645	Green Mountain Energy	\$11,500		Failure to respond to customer complaints.
3/15/2005	30740	Entergy Gulf States	\$1,600		Failure to respond to customer complaints.
7/29/2005	31053	USAVE Energy	\$800		Deceptive Marketing
10/14/2005	30158	Hino Electric	\$20,000		Violations related to low- income discount program, disconnection violations, record retention.
1/27/2006	31889	Certain Energy	\$2,900		Failure to meet renewable energy requirements.
2/13/2006	31887	Liberty Power	\$1,100		Failure to meet renewable energy requirements.
5/1/2006	30215 / 30216	Cap Rock Energy	\$234,049	\$1,416,000	Charging unauthorized late fees and an unauthorized rate.
10/30/2006	32493	Affordable Power Plan	\$223,000		Improper disconnection of electricity customers.
Pending	32824	Utility Choice	\$399,450		Failure to meet renewable energy requirements.
Pending	32846	ACN Energy	\$15,150		Failure to meet renewable energy requirements.
Pending	33138	Freedom Power	\$21,050		Improper disconnection of electricity customers.
Pending	33384	Tri-Eagle Energy and Starlight Energy	\$0	\$1,100,000 (estimated)	Failure to honor fixed price in contract.
Pending	ending 33491 Freedom revocation of certificate to operate		ertificate to te	Disconnection violations, failure to meet financial qualification, failure to comply with customer protection rules.	

 Table 2: Summary of Retail Enforcement Cases

The Commission's Infrastructure and Reliability Division conducts oversight activities related to transmission and distribution infrastructure in the state. Infrastructure monitoring includes:

- ongoing review of Commission rules related to reliability and service quality;
- monitoring of service quality standards by reviewing customer complaint information and other materials;

- monitoring of compliance with service quality standards through review of annual reports; and
- informal and formal attempts to resolve issues related to service quality or to compel compliance when potential violations are discovered.

In 2005 and 2006, the Executive Director also initiated enforcement proceedings against nine TDUs for failure to comply with the electric service quality and reliability standards provided by PURA §38.005. Six enforcement cases have been finalized with a total of \$192,000 in penalties assessed against the utilities. Settlements have been reached in the three remaining cases and are awaiting Commission approval. The following table summarizes these enforcement actions and their resolution.

Date Finalized	Docket	Company	Penalty or Recommended Penalty	Refund (if applicable)	Alleged Violation
6/29/2006	32305	Texas-New Mexico Power	\$28,000		Failure to meet service quality and reliability standards from 2001 to 2004.
7/20/2006	32307	El Paso Electric	\$27,000		Failure to meet service quality and reliability standards from 2001 to 2004.
8/10/2006	32304	Southwestern Electric Power	\$11,110		Failure to meet service quality and reliability standards from 2001 to 2004.
8/10/2006	32331	AEP Texas North	\$35,380		Failure to meet service quality and reliability standards from 2001 to 2004.
8/10/2006	32330	AEP Texas Central	\$54,540		Failure to meet service quality and reliability standards from 2001 to 2004.
10/30/2006	32729	Southwestern Public Service	\$36,000		Failure to meet service quality and reliability standards from 2001 to 2004.
11/03/06	32309	CenterPoint Energy	\$58,000		Failure to meet service quality and reliability standards from 2001 to 2004.
12/05/06	32018	TXU Electric Delivery	\$100,000	\$125,000 (in form of energy efficiency improveme nt for customers)	Failure to meet service quality and reliability standards from 2001 to 2004.
pending	32306	Entergy Gulf States	\$38,000		Failure to meet service quality and reliability standards from 2001 to 2004.

Table 3: Summary of Service Quality and Reliability Cases

### 2. Wholesale Market Oversight

#### a. Oversight Activities

The Commission's Wholesale Market Oversight (WMO) section of the Electric Industry Oversight Division conducts oversight activities with respect to the wholesale electric market. WMO has been assisted in these activities by the Commission's consultant, Potomac Economics, and the compliance group at ERCOT. (Beginning in September 2006, the Commission selected Potomac Economics to serve as the IMM for ERCOT. Potomac will now be performing an expanded role in analyzing market efficiency and the conduct of market participants.) Potomac has developed computer programs to analyze market operations and provide reports. These programs permit it to summarize and review large amounts of market data on a daily basis. These tools are relied upon by Commission Staff and now by the IMM to identify areas requiring further investigation or enforcement activities, and to prepare other reports.

Wholesale market oversight activities include:

- review of the operations of the market as measured through the analysis of ERCOT wholesale market data, Quarterly Wholesale Electricity Transaction Reports filed by market participants with the Commission (relating to bilateral transactions), and other competitive market indicators;
- review of Commission rules and the ERCOT Protocols governing the operation of the wholesale market in order to, among other things, identify gaming opportunities and inefficiencies in the rules;
- detection and investigation of possible market manipulation and market power abuses identified by the IMM for the ERCOT wholesale market;
- detection and investigation of possible violations of Commission rules, PURA, and the ERCOT Protocols;
- analysis of the operations of the ERCOT wholesale market using computerized models and tools developed by the Commission's IMM, Potomac Economics; and
- informal and formal measures to compel compliance when potential violations are discovered.

### b. Investigations and Enforcement

During the period January 2005 to December 2006, the Commission assessed over \$63,000 in administrative penalties for violations of Commission rules or Texas statutes related to the wholesale electric market, and ordered over \$730,000 in restitution to customers as part of the resolution of investigations or enforcement actions.
The chart below provides a summary of the enforcement cases brought by the Executive Director since January 2005. In addition to the cases listed here, the Commission Staff conducted a number of other investigations where no violation or a minor instance of non-compliance was discovered or where the company properly remedied an inadvertent violation after being served with a notice of the violation. At any given time, the Commission is conducting a number of investigations at various stages that are not publicly disclosed.

Date Finalized	Docket	Company	Penalty or Recommended Penalty	Refund (if applicable)	Alleged Violation
8/23/2005	30988	CPS Energy	\$0	\$600,000	Improper scheduling of wind energy.
2/13/2006	32177	Texas Independent Energy	\$35,452	\$133,744	Failure to comply with ERCOT Protocols in providing ancillary services.
2/28/2006	32300	Wharton County Power Partners	\$20,000	\$0	Failure to comply with ERCOT Protocols – failure to notify ERCOT of power plant retirement.
9/8/2006	33047	FPL Energy	\$4,574	\$2,287	Failure to comply with ERCOT Protocols in providing ancillary services.
10/13/2006	33177	Constellation	\$3,308	\$1,103	Failure to comply with ERCOT Protocols in providing ancillary services.

 Table 4: Summary of Wholesale Enforcement Cases

During the last two years, the Commission also completed a number of projects related to market design:

- WMO Staff analyzed the reliability and efficiency of the ERCOT markets during the hours in which generators ramp up and ramp down to follow the aggregate customer demand for electricity.<sup>43</sup> Staff identified changes to market rules that would improve reliability and market efficiency in these hours. Several Protocol revisions were approved to define performance measures for qualified scheduling entities (QSEs) and impose penalties if performance falls below certain threshold levels.
- Potomac Economics, serving as a consultant to the Commission, conducted an investigation into relative shortages of energy in the balancing energy market, which is used by ERCOT to ensure that supply and demand match at all times,

<sup>&</sup>lt;sup>43</sup> Investigation into Frequency Control Related Issues During Ramp Periods in ERCOT, Project No. 30302.

and usually comprises around 5% of the energy used in the market.<sup>44</sup> Potomac concluded that a significant amount of available energy that could have been offered into the balancing energy market was not, because of barriers and economic risks inherent in the balancing energy market, rather than physical or economic withholding. Potomac's report expressed the view that such inefficiencies will be addressed when ERCOT implements a nodal market design for the wholesale market in 2009.

• The Commission initiated a project to monitor the implementation of recommendations by Potomac Economics to improve market efficiency and facilitate enforcement of ancillary service market rules.<sup>45</sup> ERCOT and its stakeholders addressed 10 of the 14 recommendations that were found to be practical within the current zonal market system.

#### c. ERCOT State of the Market Report 2005

Potomac Economics recently completed its evaluation of the ERCOT wholesale electricity market and produced the 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets.<sup>46</sup> Potomac recognized positive steps taken by ERCOT to improve market performance and concluded: "We find improvements in a number of areas over the results in prior years that can be attributed to changes in the market rules or operation of the markets." These improvements include reducing the cost of resolving local congestion by about 4% in 2005 compared to 2004.

The report does state that "current market rules and procedures are resulting in systematic inefficiencies." However, the report noted that such inefficiencies will be addressed when ERCOT implements a nodal wholesale market design in 2009. In particular, Potomac expressed concerns about available capacity that is not offered into the balancing energy market because of a variety of legitimate factors. The nodal market will result in better utilization of these resources through pricing of power at the point where generators deliver power to the electric network and through a day-ahead market. In the end, the report concludes that there is little evidence that "the large amount of unoffered capacity represents strategic withholding."

<sup>&</sup>lt;sup>44</sup> Staff Investigation into the Electric Wholesale Market Activities of TXU, Docket No. 30513, Investigation into the Causes for the Shortages of Energy in the ERCOT Balancing Energy Market and into the Wholesale Market Activities of TXU from October 27 to December 8, 2004 (Apr. 2005).

<sup>&</sup>lt;sup>45</sup> 2004 Assessment of the Operation of the ERCOT Wholesale Electricity Market, Potomac Economics, Ltd. (Nov. 2004). <u>http://www.puc.state.tx.us/wmo/documents/index.cfm</u>

<sup>&</sup>lt;sup>46</sup> 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd. (Jul. 2006). <u>http://www.puc.state.tx.us/wmo/documents/index.cfm</u>

# d. Independent Market Monitor and Acquisition of IMM Services

The Commission initiated a project to establish an IMM for the wholesale market in the ERCOT region, as required under Chapter 39 of PURA.<sup>47</sup> The Legislature directed that the Commission by rule define: (1) the market monitor's responsibilities, (2) the standards for funding the market monitor, (3) qualifications for the personnel of the market monitor. The rule fulfils this mandate. The rule defines the objectives of market monitoring to be: to detect and prevent market manipulation strategies and market power abuses, to evaluate the operations of the wholesale market and the market rules, and to propose changes to enhance market efficiency.

As part of its responsibilities, the IMM is charged with monitoring wholesale markets in the ERCOT power region, including the Balancing Energy market and the Ancillary Services markets. The IMM is charged with critically analyzing the ERCOT Protocols and related procedures and practices that affect supply, demand, and the efficient functioning of those markets. The IMM is to propose changes to market rules if it identifies opportunities for market manipulations and other economic inefficiencies, and make recommendations to the Commission regarding measures to enhance the efficiency of the wholesale market and methods to correct market design flaws it has identified.

The IMM has the authority to conduct monitoring, analysis and reporting activities but has no enforcement authority. The rule provides that the IMM shall report directly to the Commission any potential market manipulations, including market power abuse, and any violations of Commission rules or ERCOT Protocols.

The rule establishes the IMM as an office independent from ERCOT, which is not subject to the supervision of ERCOT with respect to its monitoring and investigative activities. ERCOT funds the operations of the IMM, but the budget and expenditures of the IMM are subject to Commission supervision and oversight. The ethical standards governing the IMM director and staff ensure that there will be no conflict of interest between the IMM and a market participant or an affiliate of a market participant. The rule took effect in April 2006.

The Commission and ERCOT issued a request for proposals to perform the market monitoring function in March 2006. Six companies submitted proposals to supply the services. In August 2006, based on a thorough evaluation of the proposals, the Commission selected Potomac Economics to serve as the IMM. Potomac has prior experience with evaluating the ERCOT market, having served as an advisor to the Commission on wholesale market issues. It also has extensive experience in organized wholesale electricity markets in other regions of the United States.

<sup>&</sup>lt;sup>47</sup> Project No. 31111, *loc. cit.* The 2005 amendments to PURA (Senate Bill 408) included provisions for an Independent Market Monitor to be funded by ERCOT.

## **3. ERCOT** Oversight

Senate Bill 408 clarified that the Commission has complete authority to oversee and investigate ERCOT's finances, budget, and operations as necessary to ensure that ERCOT is accountable. The Commission continues to expend significant resources in overseeing ERCOT.

## a. Budget Oversight

Senior Commission Staff meets regularly with ERCOT management to discuss issues such as ERCOT's budget and fee, employee-related expenses, staffing needs, and internal controls necessary to ensure that ERCOT operates in an efficient manner.

Senior Commission Staff also worked with ERCOT to develop new employee recruiting, retention, and relocation policies. Additionally, the Commission and ERCOT jointly commissioned independent reviews of ERCOT's organizational structure and compensation policies. Finally, ERCOT continues to strengthen its internal controls after weaknesses were identified by auditors retained in response to the contracting and employee-related fraud scandals that were disclosed in 2004. Over the course of 2006, ERCOT consulted with Deloitte and Touche, LLP concerning ERCOT's internal controls. In a letter reporting the results of the consultation, Deloitte concluded that ERCOT "has taken ownership of ensuring sustainability of an internal control environment that efficiently and effectively controls risks." Deloitte tested 145 controls that ERCOT identified as key controls and found that the majority were working effectively.

## b. Operations Oversight

In late December 2005, the Commission became aware of a major outage of the retail customer registration systems operated by ERCOT. The outage began on Monday, December 26, and resulted in the suspension of all customer switching transactions and meter reading transactions until the system was restored on Friday, December 30.

PUC SUBST. R. 25.362(h)(3) requires that ERCOT management immediately inform the Commission's Executive Director if, among other things, ERCOT management becomes aware of any event or situation that could reasonably be anticipated to adversely affect the reliability of the regional electric network, the accounting procedures applicable to ERCOT or the ERCOT market, ERCOT's performance of activities related to the customer registration function, or the public's confidence in the ERCOT market or in ERCOT's performance of its duties. The delay in notifying the Commission of the retail outage indicated a lack of awareness concerning this obligation among senior management at ERCOT, and resulted in a sanction letter from the Commission warning ERCOT that future non-compliance could result in the assessment of administrative penalties against ERCOT.

On April 17, 2006, a combination of unseasonably hot weather statewide, an inaccurate forecast by ERCOT of the likely demand for power on that day, over 14,000 MW of generation unavailable because of seasonal maintenance, and the unexpected outages of 2,440 MW of generation power plants that were on-line led to a shortage of electricity within the ERCOT power region, resulting in the need to institute rotating outages to 1,000 MW of retail customers for a period of several hours. While ERCOT's grid operators generally performed admirably and acted quickly and decisively in implementing the Emergency Electric Curtailment Plan, ERCOT failed to provide adequate notice to the Commission and other statewide and local officials of the impending shortages and possible need for rotating outages. As a result, local officials, including law enforcement, were unprepared for the loss of electrical power to street lights and customers.

Since the April event, the Commission has spent significant resources in creating emergency communications procedures with ERCOT so that ERCOT will provide adequate notice to the Commission, the State Operations Center, and other state and local officials of impending shortages of electricity. These procedures were implemented during the summer of 2006, and led to several alerts being sent on days when electricity reserves reached levels where unplanned outages could have created emergency conditions. The Commission has also worked with utilities outside of ERCOT to establish similar notification systems.

ERCOT has also amended its emergency procedures to provide a media appeal for voluntary conservation by customers at an earlier time in the emergency procedures in order to better ensure that customers are informed of conditions and can take actions to lessen the chance of rotating outages. To complement these communications, the Commission created a new color coded Conservation Alert system on its web page to advise customers as to the necessity of conservation during times when high electricity demand is expected, or when shortages are imminent.

The Commission also continues to finalize its review of the events of April 17 and investigate areas where market participants or ERCOT failed to comply with Commission rules and the ERCOT Protocols.

# **D.** NON-ERCOT UTILITIES: MARKET DEVELOPMENT ACTIVITIES

Full retail competition in all areas of Texas outside of ERCOT has been delayed either by legislative mandate or by the Commission's adoption of a rule or order. Senate Bill 7 delayed competition for the EPE service area until the end of the rate freeze period resulting from EPE's 1995 bankruptcy proceeding. The Legislature delayed competition in the SPS service area (the Texas panhandle) until 2007, at the earliest.

The Commission delayed competition for Entergy Gulf States, Inc. (EGSI) (southeast Texas), SWEPCO (northeast Texas), and AEP-TNC-SPP because of a lack of

independence in the administration of transmission services, a lack of necessary market institutions, and a lack of open and non-discriminatory access to the transmission grid.

### 1. Entergy Gulf States, Inc.

Retail competition was delayed in the EGSI area by a Commission order issued in late 2001, and the Commission conducted a number of subsequent activities related to the prospect of introducing competition in the EGSI area.<sup>48</sup> In 2004, the Commission rejected EGSI's plan for competition in its region.<sup>49</sup> PURA §39.453 (added by 2005 Amendments: House Bill 1567) states that the Commission may not authorize customer choice until the Commission certifies the applicable power region as a qualifying power region under PURA §39.152(a). In December 2005, the Commission opened a project to evaluate EGSI's options for its applicable power region. The issues related to identifying an appropriate power region relate to the independence of the organization that would operate the transmission system.

## a. Qualified Power Region for Entergy

As the first step in evaluating EGSI's options for a competitive power region, EGSI filed a plan for identifying that region, pursuant to PURA §39.452.<sup>50</sup> Following a public workshop in March 2006, there was no consensus among interested parties concerning which power region was the best option for EGSI. However, the parties agreed that EGSI should develop additional information about the options and present the information as part of its January 2007 filing of a transition to competition plan. In order to assist its evaluation of the plan, the Commission invited public comment on the types of information that should be included in EGSI's application. After reviewing the comments, the Commission on September 12, 2006, provided EGSI a list of information needed for this evaluation, and the project was concluded. A proceeding to identify the power region is expected to be filed in January.

## b. Entergy Storm Cost Recovery

On September 24, 2005, Hurricane Rita struck the Texas Gulf Coast area, causing extensive damage to property and loss of electric power in large areas of Texas. As a result of the hurricane, EGSI suffered extensive damage to its facilities, particularly its transmission and distribution facilities that are necessary to provide service to customers.

<sup>&</sup>lt;sup>48</sup> Public Utility Commission of Texas Staff Petition to Determine Readiness for Retail Competition in the Portions of Texas within the Southeastern Reliability Council, Docket No. 24469, Final Order (Dec. 20, 2001).

<sup>&</sup>lt;sup>49</sup> Petition of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area of Texas, Docket No. 28818, Final Order (Jul. 12, 2004).

<sup>&</sup>lt;sup>50</sup> Entergy Gulf States, Inc.'s Plan for Identifying Applicable Power Region Pursuant to PURA §39.452(f), Project No. 32217, EGSI's Plan for Identifying Applicable Power Region (Dec. 22, 2005).

The Commission initiated a project to receive information from EGSI concerning the amount of costs that it incurred in restoring service to its Texas customers.<sup>51</sup> While the project was pending, House Bill 163 was enacted, establishing a procedure by which EGSI could recover its reasonable and necessary hurricane reconstruction costs either through a rate proceeding or through a securitization proceeding. On July 5, 2006, EGSI submitted its application, seeking a Commission determination of its hurricane reconstruction costs.<sup>52</sup>

On December 1, 2006, the Commission issued an Order approving a unanimous settlement that determined that the total amount of Hurricane Rita reconstruction costs incurred by EGSI through March 31, 2006, was \$393,236,384 plus carrying costs at the rate of 7.9% per annum. As agreed in the settlement, this amount will be reduced by amounts that EGSI has received and will receive from insurance proceeds and from government grants (if consistent with the grant). Under House Bill 163, EGSI can now request, in a separate proceeding, that the Commission authorize EGSI to recover these and other qualified costs through the issuance of "transition bonds," if the use of such bonds provides greater tangible and quantifiable benefits to ratepayers than would have been achieved without the use of transition bonds.

# 2. Southwest Power Pool

The SPP portion of Texas is another area in which retail competition has been delayed by the Commission.<sup>53</sup> The SPP RTO is a multi-state organization comprised of 48 members including cooperatives, independent power producers (IPPs), investor-owned utilities, marketers, municipals and state agencies. In August of 2006, the Commission approved a rule, discussed further in Section II.A.1 of this report, to further delay competition in SWEPCO and AEP-TNC-SPP, the areas of Texas served in the SPP region. In this rulemaking, the Commission determined that the power region including SWEPCO and AEP-TNC-SPP remains unable to offer fair competition and reliable service to all customer classes at this time; therefore it delayed retail customer choice until at least January 1, 2011. The legislation that mandated retail competition in Texas delayed retail competition in the Texas Panhandle until January 1, 2007, at the earliest.<sup>54</sup> This area is served by SPS, and competition. SPS has not filed such a plan and has not given any indication that it intends to do so soon.

<sup>&</sup>lt;sup>51</sup> PUC Proceeding to Review Policies and Procedures Related to Exceptional Storm Damage Costs Caused by Hurricane Rita, Project No. 32003, Update to the Responses to the Commission's Questions Concerning Hurricane Rita Costs (May 15, 2006).

<sup>&</sup>lt;sup>52</sup> Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs, Docket No. 32907, Order (Dec. 1, 2006). With the initiation of this proceeding, Project No. 32003 was terminated.

<sup>&</sup>lt;sup>53</sup> Project No. 32104, *loc. cit.* 

<sup>&</sup>lt;sup>54</sup> PURA §39.401 et seq.

Although retail competition for all customer classes is not viable in SPP at this time, SPP and participants in SPP have taken key steps towards enhancing wholesale competition within the territory:

- On October 1, 2004, FERC granted SPP's application for status as a RTO. With some exceptions, participant states which require approval of the RTO or utilities' participation in it have issued orders providing such approval.
  - Arkansas has conditionally granted the request of three utilities and SPP to transfer functional control of transmission facilities to SPP, allowing for participation in the SPP RTO and the SPP Energy Imbalance Services (EIS) market, and has conditionally approved SPP's application for a CCN to transact the business of a public utility in Arkansas.
  - Missouri has approved, on a conditional basis, applications of two of the utilities it regulates to transfer functional control of certain transmission assets to SPP.
  - Kansas has approved the Kansas regulated electric utilities' joint application for authority to transfer functional control of certain transmission facilities to SPP, and has approved SPP's application for a Certificate of Convenience and Authority to manage and coordinate the use of certain transmission facilities in Kansas.
  - Louisiana and New Mexico have filed a petition with the U.S. Court of Appeals requesting that FERC's approval of a number of the SPP RTO provisions be reversed. The states allege that FERC exceeded its authority under the Federal Power Act in approving the SPP RTO.
  - No action is needed by Texas or Oklahoma.
- Parties have been working towards the implementation of the EIS market. Selected aspects of EIS include a Spot Balancing Energy Market, locational imbalance pricing, hourly settlement, and self-commitment of resources by owner. The EIS is expected to go live in 2007.

As demonstrated by these steps, SPP and its participants are active in working to enhance wholesale competition within the territory.

# 3. El Paso Electric Company

Retail competition was not scheduled for EPE until its rate freeze was to expire in 2005.<sup>55</sup> At the end of the rate freeze, the Commission opened a project to evaluate the introduction of retail competition in the El Paso area.

<sup>&</sup>lt;sup>55</sup> PURA §39.102.

After conducting workshops in El Paso and Austin and soliciting comments, the Commission adopted a rule, concluding that the area in which EPE is located is unable to offer fair competition to all retail customer classes in Texas, and further delayed customer choice beyond 2005.<sup>56</sup> The rule provides that EPE's rates will be regulated under traditional cost-of-service regulation until the date the Commission authorizes EPE to implement full customer choice. The Commission also established a sequence of market development activities that must be completed prior to the introduction of retail choice in the El Paso area. These activities include:

- development, approval, and operation of an RTO for the EPE region;
- development of retail market protocols to facilitate retail competition;
- development of a balancing energy market, a market for ancillary services, and a market-based congestion management system for the wholesale market in the region;
- implementation of a seams agreement with adjacent power regions to reduce barriers to entry and facilitate competition;
- implementation of a business separation plan, unbundled transmission and distribution rates, and price to beat rates;
- approval of a qualified power region pursuant to PURA §39.152; and
- implementation and evaluation of a pilot program.

EPE is located in the Western Electricity Coordinating Council (WECC) service territory, which extends from Canada to Mexico, including the provinces of Alberta and British Columbia, the northern portion of Baja California, and all or portions of 14 western states. This location makes the transition to competition for EPE very different from that of companies within ERCOT. EPE is working with WestConnect, a group of utility companies providing transmission service in the southwestern United States, to assess stakeholder and market needs regarding the western wholesale electricity market. WestConnect is working to enhance the wholesale electricity market in the west, with initiatives that include an experimental regional tariff, regional planning, and a virtual control area to investigate the feasibility of a single control area within a portion of the WECC. The efforts of WestConnect may eventually result in the development of an RTO within a portion of the WECC.

# **E. CUSTOMER EDUCATION ACTIVITIES**

The Commission is required to develop and implement an educational program to inform customers, including low-income and non-English-speaking customers, about changes in the provision of electric service resulting from the opening of the retail electric market.<sup>57</sup>

<sup>&</sup>lt;sup>56</sup> *PUC Evaluation of the Readiness of the El Paso Area for Retail Competition in Electricity*, Project No. 28971, Order Adopting New §25.421 (Oct. 18, 2004).

<sup>&</sup>lt;sup>57</sup> PURA §39.902.

Since its inception in February of 2001, the "Texas Electric Choice" campaign has worked to educate Texans about the changes and choices in the retail electric market. The fourth and fifth years of the campaign (September 2004 through August 2006) continued the previous years' focus on educating Texans about Electric Choice and their choices in electric providers.

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

#### 1. Outreach and Public Service Announcements

- Lone Star Radio Network. This series of public service announcements about Electric Choice on a statewide network of radio stations reached an estimated cumulative audience of 2.7 million listeners.
- Recruitment of Education Partners. Efforts to recruit community-based organizations and businesses as "Power Partners" to help educate Texans about Electric Choice reached an estimated 312,440 people during FY 2006. At the end of FY 2006, 350 organizations were participating in the program. The Commission recruited 45 local police departments across the state to distribute nearly 200,000 pieces of literature and promotional items during the "National Night Out" events in 2005 and 2006.
- Televised Outreach Events. In June 2006, the Commission sponsored four days of televised outreach events in conjunction with local broadcast news stations in Dallas, Houston, and the Rio Grande Valley. The events reached 2 million viewers and generated considerable traffic to the Commission's Electric Choice call center and Web sites.
- TAB NCSA Program. The Commission participated in the Texas Association of Broadcasters' Non-Commercial Service Announcement program, which allowed the Commission's public service announcements (PSAs) on Electric Choice to be aired throughout deregulated retail electric markets in Texas (a cumulative audience of nearly 3 million) at about one-fifth the cost of buying commercial airtime. The Commission's PSA, starring the cast of the "Greater Tuna" theatrical series, won a bronze "Addy" in 2006.

## 2. Websites

The Texas Electric Choice campaign Website, <u>www.PowerToChoose.org</u>, and its Spanish-language counterpart, <u>www.PoderDeEscoger.org</u>, are vital parts of the customer education process. Activity on these websites during the fourth and fifth years of the campaign was:

• Unique Visitors: 737,177

•	Page Views:	13,617,555
•	Downloads:	405,539

### 3. Answer Center

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

•	Total Calls:	229,544
•	Total Representative-assisted Calls:	173,190
•	Total Spanish-Language Calls:	22,351

#### 4. Educational Literature

Brochures, fact sheets, and other educational materials are distributed via e-mail, at campaign events, through a network of community-based organizations, and via the campaign's Websites and Answer Center. Fact sheets on a number of topics are routinely created and updated for distribution as part of the campaign's outreach efforts. The Commission distributed 606,524 information products in FY 2006 through its Texas Electric Choice campaign.

# F. ADMINISTRATION OF THE SYSTEM BENEFIT FUND

Money in the SBF can be appropriated for the purposes provided by PURA or other law.<sup>58</sup> The purposes of the SBF as amended in the 79<sup>th</sup> Legislative Session are to fund:

- an electric rate discount (10% to 20%) for low-income customers, also referred to as LITE-UP (Low-Income Telephone and Electric Utilities Program);
- one-time bill payment assistance to electric customers who are or who have in their households one or more seriously ill or disabled low-income persons and who have been threatened with disconnection for nonpayment;
- appropriations to the Commission for customer education programs, to the Commission and Office of Public Utility Counsel (OPUC) for administrative costs, and to the Commission and the Heath and Human Services Commission for expenses incurred in the implementation and administration of an integrated process for determining eligibility for the low-income discount; and

<sup>&</sup>lt;sup>58</sup> PURA §39.903(a).

• a targeted low-income energy efficiency program administered by the Texas Department of Housing and Community Affairs.

The one time bill payment assistance program was added to the statute by the 79<sup>th</sup> Legislature in Senate Bill 408. Additionally, the 79<sup>th</sup> Legislature amended the statute to allow the Commission to set the rate discount at an amount lower than 10%.

The SBF is funded through a non-bypassable delivery charge set by the Commission each year. The fee is currently set at the statutory cap of 65 cents per MWh. As of September 2006, the fund balance was approximately \$257 million, with approximately \$140 million in annual revenues.

The funding of the low-income discount program has historically been the main purpose of the SBF. The Commission initially set the low-income discount at 10%. In late 2002, the Commission had sufficient funds available to increase the low-income discount to 17%. The 78<sup>th</sup> Legislature approved appropriations sufficient to provide a 10% discount for low-income customers, funding for customer education programs, and administrative costs for OPUC. No funds were appropriated for weatherization programs or the property tax replacement, which were also original purposes of the fund. The 79<sup>th</sup> Legislature made no appropriations for the electric rate discount for the FY 2006 to 2007 biennium, and, therefore, discounts could not be provided during this biennium.

The 79<sup>th</sup> Legislature appropriated funds in the amount of \$3,625,842 for each year of the FY 2006 to 2007 biennium for Commission customer education programs, and for administrative costs incurred by the Commission in implementing Chapter 39 of PURA. With these appropriations, the Commission was able to continue its work promoting, developing, and monitoring the deregulated markets as required in Chapter 39 of PURA.

# G. ELECTRIC BILL-PAYMENT HISTORY DATABASE

Amendments to PURA were enacted recently to prohibit a REP from using an applicant's credit history, credit score, or utility payment data to deny an applicant's request for service as of January 1, 2007.<sup>59</sup> A REP is, however, permitted to use the applicant's electric bill-payment history for this purpose. House Bill 412 also required the Commission to conduct a public workshop to discuss the merits of both voluntary and mandatory databases to determine whether a customer has a satisfactory electric bill-payment history and to provide a report on its conclusions. Commission Staff conducted a workshop pursuant to this requirement. The information obtained through the workshop is the primary basis for the information and conclusions discussed in this section.

The development of an electric bill-payment history database, whether voluntary or mandatory, could be beneficial for both REPs and customers. Possible benefits include:

<sup>&</sup>lt;sup>59</sup> PURA §17.008, added by House Bill 412, 79th Legislative Session.

- The simplification of the application process for retail electric service. An electric bill-payment history database could increase enrollment efficiency for REPs and decrease the complications of switching for customers. Under the current enrollment process, a REP may request an applicant to provide a letter outlining the applicant's history of electric bill-payment history. The applicant would request such a letter from their previous (or current) provider, or authorize a REP-to-REP exchange of information. The use of a database could allow the REP to obtain authorization from the applicant during the application process and access the applicant's electric bill-payment history from the database, which would eliminate the time and effort currently required of the applicant, the new REP, and the previous provider to request and provide the information.
- The standardization of the information obtained by REPs. Currently, the letters relating to a customer's bill-payment history include various information that can help the new REP assess whether an applicant should be enrolled. However, the letters are not standardized and do not necessarily contain the information the new REP would like to have to complete its evaluation. Information within each letter varies and includes information such as the number of disconnect notices issued, the number of service terminations or disconnections, the number of late payments made, whether or not the final bill was paid, and information concerning any returned checks. A database could provide for the same body of information, which would allow for a more consistent assessment of an applicant's eligibility and deposit requirements.
- The ability to evaluate the applicant's full history. A database could allow REPs to access and review information beyond a twelve-month period to determine whether a customer has a satisfactory electric bill-payment history. This would provide a broader view of a customer's payment history. Depending on the database operator and database model chosen, it is possible that the database could include information from companies outside of Texas, which would provide better information on applicants who have moved from out of state. Such a database would probably also provide payment information on customers who do not have a traditional credit history.
- The reduction in loss potential. A database would help identify customers who have not paid their electric bill and are true high risk customers. Depending on the database model and how it is permitted to be used, a database could also help REPs obtain contact information for customers who have left their service address without paying outstanding electric bills.

The development of an electric bill-payment history database, whether voluntary or mandatory, could also pose problems for both REPs and customers. Possible problems and issues with the creation of a database include:

• The security of customer information. One or more centralized databases of electric customer information could be subject to data loss and theft if the information flowing to and from parties, and the storage and use of the

information, are not properly secured. Issues relating to accountability in the event of data loss and theft would have to be addressed.

- The adequacy of the data. Participation by a sufficient number of REPs would be required for any database to contain sufficient data to provide a full electric bill-payment history for enough customers to make the database useful. Participation of utilities outside of ERCOT, municipal utilities, and electric cooperatives could help to ensure the completeness of a database. However, the existence of multiple databases may increase the likelihood that databases will not get sufficient information if providers do not want to participate in more than one database.
- The compatibility of computer systems. Whether one or multiple databases are operated, electric REPs and the database operator will have to ensure that their systems can communicate. This may require time, personnel and investments in systems and methods of communication. The existence of multiple databases may increase the need for such resources.
- The legality of the use of information. Regardless of whether a database is mandatory or voluntary, REPs would be obligated to use the information only as permitted by applicable laws. However, a voluntary database, in which the REPs or the database operator determine the inputs and outputs, may be more likely to communicate information that could be used in ways that are not consistent with applicable laws than would a mandatory database in which the commission has oversight over the information to be exchanged.

To date, at least two companies have developed concepts of electric bill-payment history databases for Texas. Although some REPs have considered participation, for various reasons no database exists today. This has raised the question of whether a database of electric bill-payment history can be developed voluntarily or if development can be achieved only through mandate.

Voluntary development of a database means that participation is a business decision by each REP. Business decisions can change at the REP's discretion and can be expected to be based on each company's assessment of its best interest, rather than what is in the best interest of competition in the market. Therefore, it is not certain that the participation of REPs in the database would be sufficient to ensure the availability of sufficient information to provide a comprehensive credit tool. If REPs have the discretion to decide not to participate, the potential benefits for the entities and customers may not be fully realized, and entities may have to maintain other means of obtaining and managing payment information.

A mandatory database could ensure that a sufficient amount of information is available in the database by requiring sufficient and accurate information. Additionally, Commission oversight of a mandatory database could ensure that customer protection issues are properly considered in the operation of the database.

# III. EFFECTS OF COMPETITION ON RATES AND SERVICE

The biggest challenge for retail providers and consumers in the Texas retail electric market in the past two years has been significant price increases in wholesale electricity. In a market of steadily increasing prices, competitive REPs were able to offer prices below the price to beat and attract customers away from affiliate REPs. New REPs continued to enter the marketplace, selling diverse products ranging from traditional fixed and variable rate products to renewable power to "time-of-use" products for more sophisticated industrial customers.

As of October 2006, 2 million Texas customers, accounting for almost 34% of the market, were receiving power from providers other than their traditional affiliated REP. In November 2006, ERCOT handled its 3 millionth customer switch. Overall more than 12.5 million customers have switched retail providers or moved in to new homes or business locations. Each of these events represents a customer making a choice of provider, whether that choice was the affiliated REP or a new provider. Though the significant run-up in natural gas prices at the end of 2005 and beginning of 2006 resulted in significant price increases for most electric customers, the market appears to have handled the uncertainty relatively well, and most customers are aware of their many options to save on electricity.

Market prices for power at both the wholesale and retail level have increased since 2002, primarily because of increases in the price of natural gas used to fuel electric generation. Fifty percent of the electricity in the Texas market is generated by the burning of natural gas; thus natural gas prices are a major factor in Texas electric prices. Natural gas futures prices tripled from January 1, 2002, to September 1, 2006. For a brief time in late 2005 after Hurricanes Katrina and Rita, natural gas prices were more than four times their 2002 levels. Because of these higher gas prices, wholesale power prices increased in 2005. Natural gas prices moderated in 2006; by October 2006, spot natural gas and wholesale electricity prices had fallen below the prices in May 2005.

Retail prices have reflected the increases in natural gas and wholesale power prices. However, the affiliated REPs did not reduce the price to beat when natural gas prices fell. PTB rates for residential and small commercial customers increased 90% from January 1, 2002, to January 1, 2005, but, for the most part, they did not change during 2006. As natural gas and wholesale electricity prices fell in 2006, the affiliated REPs, for the most part, left their prices at post-Katrina levels.<sup>60</sup> For most periods, competitive offerings have been available that provided a significant discount to the PTB rates. In late October 2006, discounts of as much as 30% off the PTB were available for residential customers. Even green electricity prices are being offered by several providers to residential customers at rates below the price to beat.

<sup>&</sup>lt;sup>60</sup> In May 2006, two affiliated REPs entered into a settlement to provide lower rates to their existing customers, and the Commission approved this reduction in rates.

Had retail competition never occurred, retail electricity prices would have increased significantly due to fuel price increases and the need for utilities to add new generating facilities to meet customer demand. A Commission report to the Legislature in March 2006 found that, had competition never occurred, regulated prices for the period 2002 through 2005 would probably have been higher than PTB rates and competitively available rates.<sup>61</sup>

As of September 2006, approximately 34% of all customers had taken advantage of their opportunity to change REP, including almost 34% of residential and nearly 40% of commercial customers. Including the largest users of electricity in the market, 56% of electricity sold in the competitive market in Texas is supplied by providers other than the traditional affiliated REP.

The impact of higher prices on individual customers has varied, depending on the customers' decisions in the competitive market. Customers had the ability to insulate themselves from price increases if they bought long-term, fixed-price contracts. This strategy has some risks, however. If their fixed-price contract expired in late 2005 or early 2006, individual customers would have seen significant increases in the price they paid for power. A small group of customers also saw major increases when a few REPs left the market abruptly, leaving their customers with higher-priced service from a POLR or a competitive REP.

# A. EFFECT OF COMPETITION ON RATES

## 1. Wholesale Market Prices

Wholesale market prices for capacity and energy in ERCOT were significantly higher in 2005 than in 2004 due to record high prices for natural gas brought on by Hurricanes Katrina and Rita. Natural gas prices fell over the course of 2006, and spot wholesale electricity prices in ERCOT during the summer of 2006 were lower than prices in 2005. Natural gas prices have a direct impact on ERCOT wholesale electricity prices since more than 70% of the installed generating capacity in ERCOT relies on natural gas as the primary fuel or the only fuel. As a result, gas-fueled generation generally sets the market price for all types of generation.

## a. Bilateral Market Prices

The ERCOT market relies on bilateral contracts between buyers and sellers of electricity as the principal mechanism by which power is traded and sold. Bilateral contracts are privately negotiated between buyers and sellers, and encompass a variety of durations,

<sup>&</sup>lt;sup>61</sup> *Response to Legislative Inquiries Concerning Competitive Retail Electric Market*, Project No. 32198, Legislative Report (Mar. 3, 2006).

terms, and pricing. As a result, the impact of changing natural gas prices affects buyers and sellers differently depending on the time at which a contract is executed and whether the contract provides for a fixed price. While bilateral agreements are negotiated in private, some daily wholesale market prices are reported to industry trade publications, and changes in these prices are generally indicative of how prices in the market as a whole are changing.

The following chart shows that the daily on-peak market price for electricity in ERCOT (blue line) rose from approximately \$40 per MWh in January 2004 to a high of about \$120 per MWh in September 2005. The high electricity prices in the ERCOT market were a direct result of the effects of Hurricanes Katrina and Rita and high winter demand, which pushed natural gas prices over \$13 per MMBtu. By August 2006, natural gas prices dropped to below \$6 per MMBtu, and electricity wholesale prices retreated to the \$60-\$70 per MWh range.



Figure 1: Market Price for Wholesale Electricity vs. Natural Gas Price 5-Day Moving Average

# b. Balancing Energy Market Prices

ERCOT obtains and deploys balancing energy to maintain the balance between load and generation and to resolve transmission congestion through a centralized auction process,

referred to herein as the "Balancing Energy Service Market." The Balancing Energy Service Market typically represents less than 5% of the total energy consumed in ERCOT, and is primarily used by ERCOT to balance supply and demand in real time. Market participants also have the option within limits to rely on the Balancing Energy Service Market to serve some or all of their power needs, in lieu of bilateral contracts. ERCOT procures balancing energy in each of the major congestion zones. At times when there is no transmission congestion, prices in each of the zones are equal. When transmission congestion limits the transfer of power between zones, prices will typically be higher in those zones that are transmission constrained. The following chart shows ERCOT balancing energy and natural gas prices. As is the case with bilateral electricity prices, balancing energy prices follow natural gas prices.



Figure 2: ERCOT Balancing Energy Price vs. Natural Gas Price 5-Day Moving Average

Balancing Energy Service Market price volatility generally results from a variety of unexpected short term factors such as unforeseen generation or transmission outages, unexpected changes in weather, and changes in transmission congestion. Other factors that affect prices are more predictable, such as natural gas prices and seasonal variations in demand for electricity.

The average price for balancing energy in ERCOT was \$44.64 per MWh in 2004 and \$72.79 per MWh in 2005, reflecting the increase in natural gas prices. In its 2005 state of

the market report, Potomac Economics noted that the increases in natural gas prices were largely due to the effects of the hurricanes on the productive capability of the Gulf Coast Region. Even though 2006 gas prices have retreated to their 2004 levels, the balancing energy average price remains in the \$60-\$80 per MWh level.

The figure below helps to clarify this point. The spark spread is the level of profitability at a given heat rate of electricity production. (Heat rate measures the amount of heat from fuel that is required to generate a unit of electric energy.) A generator with a heat rate of 7,000 Btu per kWh using natural gas priced at \$10 per MMBtu would break even at an electricity price of \$70 per MWh. The graph shows that generating units with a heat rate of 7,000 Btu per kWh would have been only marginally profitable in 2004 and the first half of 2005, but could earn \$4 to \$6 per MWh during the summers of 2005 and 2006. The higher spark spreads during the summer are indications that higher levels of demand are resulting in increasing use of less-efficient generating facilities during the summer, or that tight supplies are resulting in higher market prices during the summer.



Figure 3: 7,000 Heat Rate Spark Spread vs. Balancing Energy Price

Source: PUC and ICE

# c. Ancillary Service Capacity Market Prices

As the system operator, ERCOT deploys ancillary service capacity and balancing energy to maintain system reliability and resolve transmission congestion. For ancillary service

capacity, ERCOT assigns an obligation to each market participant based on its historical load. Market participants may "self-provide" the capacity or rely on ERCOT to acquire it for them through a centralized auction.

The figure below shows that the monthly weighted average prices for these capacity services (Regulation Up, Regulation Down, Responsive Reserve, and Non-Spinning Reserve) increased during the period from July 2004 to December 2005. This followed directly the rise in gas prices. The impact of Hurricanes Katrina and Rita pushed ancillary service prices to record highs in excess of \$30 per MW in September 2005. Ancillary service prices in the latter part of 2005 exceeded \$15 per MW for all services except for Responsive Reserve Service in December. The monthly weighted average price of all ancillary services exceeded \$10 per MW from October 2004, with prices starting a downward trend in April 2006.



Figure 4: Monthly Average Ancillary Service Prices

Source: PUC

## d. All-in Price for Electricity

A total or "all-in" cost of electricity at the wholesale level can be constructed from the costs for balancing energy, ancillary service capacity, and uplift charges.<sup>62</sup> This

<sup>&</sup>lt;sup>62</sup> 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd., *loc. cit.*, p. 3.

construction assumes that a customer buys all of its energy needs from the ERCOToperated energy and capacity markets. Energy costs make up the bulk of the all-in cost, with ancillary services and uplift charges accounting for about 5% to 8% of the total.

Uplift charges represent services that ERCOT purchases for the benefit of the market but cannot assign to a specific market participant. They are spread to the market on a load-ratio share basis. Most of the uplift charges are for Out-of-Merit Energy (OOME), Out-of-Merit Capacity (OOMC), and Reliability-Must-Run (RMR) agreements. ERCOT uses out-of-merit energy to manage local transmission congestion, and it uses out-of-merit capacity to ensure that there is enough generation capacity available on an hourly basis to ensure local reliability. RMR agreements are sometimes necessary to ensure local reliability over a longer term period. The figure below shows the estimated all-in price for electricity in ERCOT from 2002 to 2005. Prior to 2003, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. However, high natural gas prices have caused power prices to remain at levels high enough for these technologies to be economically viable.<sup>63</sup>





<sup>&</sup>lt;sup>63</sup> *Ibid.*, p. 49.

#### e. Reserve Margin

New construction of thermal generation proceeded at a slow pace in the last two years, reflecting very high reserve margins in prior years. Approximately 1,600 MW of natural gas-fired capacity was completed state-wide in 2005 and the first half of 2006, and more than 900 MW of wind generation was completed during this period.

There were not many new announcements of mothballed or retired capacity in the last two years. The relatively new 1,100 MW Hays power station, which had been mothballed in January 2004 due to low wholesale market prices, was returned to service in May 2005. The level of capacity under RMR contracts in ERCOT declined from 1,625 MW in 2004 to about 270 MW in 2006. In most cases, ERCOT developed plans to eliminate the need for these RMR contracts through transmission construction, and the TDUs built the transmission facilities that were needed for this purpose.

The wholesale market is a competitive market, in which most of the owners and developers of generation facilities respond to their perception of the market opportunities and risks, and deploy capital accordingly. Declining reserve margins and the possibility of selling power that would be produced by fuels with a lower cost than natural gas resulted in strong interest among developers in building new generating capacity in ERCOT, particularly wind and coal generation. In August 2006, ERCOT reported that it was tracking 81 active generation interconnection or change requests representing more than 40,000 MW of new capacity. Forty percent of this capacity would come from coal or lignite resources, 41% from wind, and 17% from natural gas. The coal/lignite capacity includes the 9,000 MW of new generation announced by TXU, 800 MW announced by LS Power, 750 MW announced by CPS Energy, 630 MW announced by Sempra, and 500 MW announced by Brazos Electric. For the long-term, TXU and NRG Energy have announced plans to build a combined total of more than 3,300 MW of nuclear capacity, which would come on-line in the 2014 to 2020 timeframe, and Exelon is also considering the addition of nuclear capacity in ERCOT. The following table shows the latest ERCOT five-year reserve margin projection:

	2007	2008	2009	2010	2011
Firm Load (MW)	62,110	63,206	64,838	66,436	67,922
Capacity Resources (MW)	71,577	70,693	70,632	71,208	71,245
Projected Reserve Margin	15.2%	11.8%	8.9%	7.2%	4.9%
Reserve Margin with publicly announced thermal units	15.4%	12.0%	20.0%	24.9%	23.9%

 Table 5: ERCOT Reserve Margin Projection through 2011

Source: ERCOT Capacity, Demand, Reserve Report (June 2006)

The ERCOT forecast assumes load growth of about 2.3% per year, and it incorporates known information about new plant construction, mothballed capacity, and plant retirements as of June 2006. For purposes of the forecast, ERCOT included only new

capacity that has a signed interconnection agreement and only mothballed capacity that the owners have projected will return to service. These are conservative assumptions that do not consider new capacity that may still be in the planning and development stage. The last row in the above table shows the projected reserve margins if all the recently announced generating capacity is included.

Some mothballed capacity may return to service if market expectations change. Currently, two companies are expected to return a total of approximately 1,900 MW of mothballed generation to service. This could have the effect of raising ERCOT's 2008 reserve margin projection slightly above the 12.5% target level when it issues its *Report on the Capacity, Demand, and Reserves in the ERCOT Region* in June 2007. However, the future availability of mothballed units is somewhat uncertain. Bringing mothballed generation back into service is done at the owner's discretion, based on its assessment of the economics of doing so. The Commission cannot compel a generator to bring a mothballed plant on-line. Additionally, mothballed units tend to be less efficient and have higher emissions than most in-service units, and not all mothballed units are in a condition to be returned to service. To the extent that such units are less efficient, operating them would only be economical if wholesale electricity prices are expected to be higher than they are today.

## 2. Retail Market Development and Prices

## a. Available Choices for Customers

The good news with respect to retail competition is that there is an abundance of service offers from which customers may choose; some of them offered significant savings compared to the PTB, particularly in late 2006. Indeed, many customers have exercised their ability to choose. As of September 2006, over one-third of residential customers were receiving service from a non-affiliated REP, and a number of residential customers still served by affiliated REPs had selected a plan other than the price to beat. The bad news is that as many as 50% of all residential customers continue to pay high PTB rates. One important measure of the success of retail market competition is the number of providers in the marketplace competing to provide service to customers. By June 2006, 75 REPs were providing service to customers, with other REPs in the process of beginning operation. There are 32 REPs serving at least 500 residential customers, and residential customers throughout the competitive market have multiple providers from which to choose. As of September 15, 2006, customers visiting the Commission's website promoting the competitive market would find 17 REPs offering products throughout the state.<sup>65</sup> These REPs were offering between 35 and 41 different products in various territories, including four REPs which were offering, between them, five different renewable energy options. (See the table below.)

<sup>&</sup>lt;sup>65</sup> <u>http://www.PowerToChoose.org</u>

The affiliated REPs have been allowed to offer alternative plans to their customers since January 1, 2005, and several of the affiliated REPs have taken advantage of this option, offering discounts and alternative terms of service to customers in their own territories, including renewable, variable, and fixed rate plans of various terms. In May 2006, the affiliated REPs in two territories entered into a settlement to cut the price to beat rates for all existing price to beat customers in those territories. The Commission approved the settlement agreement.<sup>66</sup>

The number of REPs and offers has increased steadily since 2002. Residential customers have at least twice as many options as they did at the time of the 2005 report on the *Scope* of Competition in Electric Markets in Texas, and in some cases three times as many options.<sup>67</sup> This suggests that the market continues to be strong, with sufficient opportunity for new providers to enter the market.

	Number of REPs Serving Residential Customers (Incl. affiliated REP)	Number of Residential Products (Incl. Price to Beat)	Number of Renewable Products
TXU ED	17	41	5
CenterPoint	17	41	5
AEP TCC	17	37	5
TNMP	17	35	5
AEP TNC	17	36	5

## Table 6: Number of REPs Serving Residential Customers, by Service Territory

# b. Residential Rates

On January 1, 2002, all existing residential customers were placed on the price to beat rates at a discount of 6% off the then-existing residential rates. As of January 1, 2005, the affiliated REPs were given the opportunity to offer rates other than the price to beat, but the requirement that the price to beat be offered to all customers continues until January 1, 2007. Affiliated REPs have the opportunity twice per year to adjust the fuel component of the price to beat rate when natural gas prices have significantly changed from their levels at the last fuel rate adjustment.

Since January 2002, affiliated REPs have requested adjustments to the fuel factors resulting in total increases in the overall price to beat of between 67% and 114%, depending on territory. The following chart illustrates those adjustments.

<sup>&</sup>lt;sup>66</sup> Docket No. 32693, *op. cit.* and Docket No. 32694, *op. cit.* 

<sup>&</sup>lt;sup>67</sup> Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas (Jan. 2005). <u>http://www.puc.state.tx.us/electric/reports/scope/2005/2005scope\_elec.pdf</u>



#### Figure 6: Increases in the Price to Beat

These price increases resulted almost entirely from changes in the natural gas price, and represent changes which, on the whole, would have occurred ultimately in either a competitive or a regulated market. Price increases have also played a major role in allowing competitive REPs the opportunity to compete in the marketplace. Had the fuel factor adjustments been delayed or not available, it is likely that much of the competition we see today would not have been possible. The following graph shows, across all five service territories, the average residential price to beat, the average competitive offer, and the average of the lowest competitive offers. During this period, REPs offered prices in all five service territories that were lower than the average lowest competitive offer.



Figure 7: Average Residential Price to Beat vs. Competitive Offers

\* Henry Hub, 20-day moving average

<sup>\*</sup>Henry Hub, 20-day moving average

In late 2005, the average competitive offer was briefly higher than the existing price to beat, as natural gas prices rose sharply above the level on which the price to beat was based, and both the average and lowest competitive offer rose slightly earlier than the price to beat. This suggests that the late 2005 price to beat adjustments were not only justified, but necessary to the health of the competitive market. Had the adjustments not occurred, it is likely that many of the existing REPs may have faced financial difficulty, and may have been forced to stop seeking new customers. Indeed, at least one major residential competitive REP did stop seeking new customers briefly during that period. By contrast, that portion of the graph for the autumn of 2006 indicates a wide margin between the PTB and competitive rates, as the PTB remained high, but the affiliated and competitive REPs reduced their non-PTB-offered prices as wholesale energy prices fell.

Savings of between 16% and 31% are available today for a typical 1,000 kWh per month residential customer. Although this level of savings amounts to only about 50% to 60% of the increases in the price to beat since 2002, and it would be difficult to determine exactly what regulated prices would be at this time, it is likely that residential customers are paying lower rates than would have been produced through regulation.



Figure 8: Price to Beat vs. Competitive Offer, by Service Territory

Natural gas price increases have led to increases in regulated electric rates throughout the country, both in regulated and competitive areas. Texas PTB rates are above the rates in most other states because Texas is more reliant on natural gas than most other states. Nearly fifty percent of ERCOT-area electricity is generated with natural gas, compared to only 18% nationally. In the ERCOT wholesale market, the market price of electricity is normally based on gas prices, because natural gas generation is always on the margin in the ERCOT market. This means that REPs must buy electricity at prices that are based

on gas-fueled generation. Electric rates in other states that are dependent on natural gas have also risen significantly. The following table shows the current price of power for major utilities in other states with high dependence on natural gas-fired generation.

Utility	State	Avg. price in cents per kWh	Statewide gas share of generation, July 2005 - June 2006
NSTAR <sup>68</sup>	Massachusetts	19.38	45.0%
Pacific Gas & Electric <sup>69</sup>	California	14.30	47.6%
Southern California Edison	California	14.80	47.6%
San Diego Gas & Electric	California	15.40	47.6%
Gulf Power <sup>70</sup>	Florida	13.57	38.1%
Tampa Electric Company	Florida	14.55	38.1%
Central Maine Power Company <sup>71</sup>	Maine	15.03	48.3%
Sierra Pacific <sup>72</sup>	Nevada 💦 👘	13.04	46.4%
TXU Price to Beat	Texas	15.00	48.6%
CenterPoint Price to Beat	Texas	16.29	48.6%
TXU Lowest Offer	Texas	13.48	48.6%
CenterPoint Lowest Offer	Texas	14.23	48.6%

 Table 7: Average Retail Price for Electricity from Selected Gas-dependent Utilities

The Commission recently requested information on the cost of electricity that customers in the competitive market were paying in September 2006. The information provided by the REPs in response to this request clearly indicates that customers that are willing to shop for a retail provider are saving money on electric service, compared to those who buy power from the affiliated REPs. The figure below shows higher percentages of residential customers of competitive REPs (CREPs) in the lower price ranges and higher percentages of customers of affiliated REPs in the higher price ranges. Ninety percent of residential customers of affiliated REPs (roughly 3 million customers) were paying in excess of 15 cents per kWh for electricity, compared to 41% of customers of competitive REPs. At the lower price ranges, 21% of customers of affiliated REPs were paying less than 14 cents per kWh, while only 1% of customers of affiliated REPs were paying less than 14 cents.

<sup>&</sup>lt;sup>68</sup> Basic Offer and TDU fees from NSTAR, <u>http://www.nstaronline.com</u>

<sup>&</sup>lt;sup>69</sup> California Utility data from California Public Utilities Commission, <u>http://www.cpuc.ca.gov</u>

<sup>&</sup>lt;sup>70</sup> Florida Utility Data from Florida Public Service Commission, <u>http://www.psc.state.fl.us</u>

<sup>&</sup>lt;sup>71</sup> Standard Offer and TDU rates from <u>http://www.cmpco.com/prices</u>

<sup>&</sup>lt;sup>72</sup> Sierra Pacific Electric Rate Schedules for Residential Customers, http://www.sierrapacific.com/services/brochures\_arch/rate\_schedules/spp\_nv\_resrates.pdf



**Figure 9: Residential Customer Price Distribution** 

The figures below show similar results for small commercial customers. These figures show information for the customers with the lowest levels of consumption (less than 50 kW of demand) and then higher levels of consumption (demand of between 50 and 1,000 kW). As with residential customers, a higher percentage of the customers of competitive REPs were paying rates in the lower cost categories, and a higher percentage of customers of the affiliated REPs were paying rates in the higher categories. The information also indicates that fewer commercial customers with a demand of less than 50 kW are switching to competitive REPs than are residential customers. During September, 33% of residential customers with a demand of less than 50 kW were served by competitive REPs.



Figure 10: Commercial Customer (less than 50 kW) Price Distribution



Figure 11: Commercial Customer (50 kW through 1,000 kW) Price Distribution

The price disparities are most apparent among the larger customers. In this group, 44% of the customers of competitive REPs and 24% of the customers of affiliated REPs were paying less than eight cents per kWh for electric service, while 40% of the customers of affiliated REPs and 8% of the customers of competitive REPs were paying in excess of 12 cents per kWh.

# **B. SWITCHING ACTIVITY**

As of September 2006, over 2.1 million individual customer premises were taking service from REPs other than their affiliated REP, based on data reported to the Commission in quarterly Performance Measures by the TDUs. This represents approximately 34% of all customer premises in the areas open to customer choice. Of these customers, 83%, or approximately 1.8 million, are residential customers. Another 319,000, or 15%, are customers taking delivery at secondary voltage levels-such as retail establishments and offices. The balance consists of approximately 5,000 large establishments that take high-voltage power, such as factories and refineries, and 37,000 un-metered lights-streetlights and some security lighting.

In September 2006, a total of 12.4 million MWh of electricity were used by customers of non-affiliated REPs, representing approximately 56% of all MWh sold that month in the area open to customer choice. This number is higher than the percentage of customer premises switched because larger commercial and industrial customers comprise a significant percentage of Texas energy usage, and these customers have been switching at higher rates than smaller customers who use less power. Though residential customers represent 83% of total switches, they represent only 20% of the electricity sold to switched customers in September of 2006.



Figure 12: Percentage of Energy Sold by Affiliate Status of REP

## 1. Residential Customer Switching

As of September 2006, 33.9% of all residential customers were taking service from a non-affiliated REP. There has been a very smooth trend of residential switching, with about 7% of residences joining the ranks of non-affiliated customers each year since 2002. More switching occurs in summer than in winter, most likely because of higher usage resulting in higher bills in the summer months. By comparison, few residential customers have elected to change providers in markets in Illinois and New England, and few REPs have attempted to compete there.<sup>73</sup> In New York, 6.7% of residential customers having about seven options available.<sup>74</sup>

Competing REPs originally focused their efforts on recruiting customers in the large urban markets of Houston and Dallas-Fort Worth, but have branched out, with most residential REPs marketing throughout the state. REPs have been most successful in the area with the highest price to beat rate, the relatively rural AEP TNC (previously West Texas Utilities) territory, where 44.4% of residential customers have switched. In the other service territories, from 32.9% to 34.6% of residential customers are with REPs other than the affiliated REP. These percentages do not include an unknown number of residential customers who originally switched to a new provider, but returned to the

<sup>&</sup>lt;sup>73</sup> Competition in Illinois Retail Electricity Markets in 2005, Illinois Commerce Commission (May 2006): p. 5.

<sup>&</sup>lt;sup>74</sup> Staff Report on the State of Competitive Energy Markets: Progress To Date and Future Opportunities, New York State Department of Public Service (Mar. 2006): p. 46.

affiliated REP at a later date, whether at price to beat or on another plan with lower rates or more desirable terms. (In other words, these customers are counted as *not* having switched.) The switching rates do not explicitly recognize that customers make a choice when they initiate service, and the percentages above would include new customers who have selected an affiliated REP as *not* having switched.





Figure 14: Competitive REP Share of Residential MWh



# 2. Secondary Voltage Level Commercial and Industrial Customer Switching

Commercial and industrial customers taking service at the secondary voltage level have shown a greater propensity to switch than residential customers. This most likely is driven by the fact that most of these customers have higher energy usage, and thus higher electric bills, than most residential customers. As of September 2006, 39.4% of commercial and industrial customers had changed providers, ranging from 34.4% in the TNMP territory to 52.3% in the AEP TCC service territory. These switching counts have grown more or less linearly since 2002, with some slight slowdown in recent months as the number of affiliated REP customers is reduced, and affiliated REPs began to offer alternative plans to these customers in an attempt to win them back.



Figure 15: Secondary Voltage Customers with Competitive REP

The largest customers in this customer class have been the most ready switchers, as is shown by the fact that 67.5% of MWh sold to this class in September 2006 were sold by REPs other than the affiliated REP. By territory, as few as 59.6% to as many as 84.8% of MWh are sold by REPs other than the affiliated REP. This wide range most likely reflects differences in the aggressiveness of the various affiliated REPs in trying to win back customers since January 2005, the date by which all affiliated REPs received the right to offer rates other than the price to beat by virtue of losing 40% of the load among customers with demand less than 1 MW.



Figure 16: Competitive REP Share of Secondary Voltage MWh

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

Primary and transmission voltage level customers tend to be large customers. Many of these customers have demand greater than 1 MW, and thus have been ineligible for price to beat since January 2002. Approximately 61% of the primary and transmission customers had switched by September 2006. This is an increase from about 42% in September 2004. Few if any of the remaining 40% of customers are on a default rate, with many of them having negotiated competitive contracts with the affiliated REP.

Approximately 68% of MWh sold to this class were provided by REPs other than the affiliated REP. This number has been roughly stable since 2004.



Figure 17: Primary Voltage Customers with Competitive REP

# C. FINANCIAL STATUS OF THE TEXAS ELECTRIC INDUSTRY

The competitive ERCOT market consists of three major categories of companies that are providing electric service: TDUs, load-serving REPs, and power generation companies (PGCs). In terms of market share, each category is dominated by several large, well-capitalized firms, almost all of which have investment-grade credit ratings from at least one major credit rating agency.<sup>75</sup> The general financial trends over the last several years for these larger participants have been favorable, with most maintaining or improving their credit ratings.

TDUs, because they remain under regulation and are essentially monopoly providers of electric delivery service, have generally stable and predictable financial characteristics. The smaller REPs and PGCs typically have smaller individual market shares and feature diverse financial qualities, which one would expect in an evolving competitive market. A

<sup>&</sup>lt;sup>75</sup> There are three major agencies that provide credit ratings for investment securities: Moody's Investors Service (Moody's), Standard and Poor's (S&P), and Fitch IBCA (Fitch). Each of these agencies provides a rating system to help investors determine the risk associated with investing in a specific company or debt instrument. A credit rating is an assessment of creditworthiness based upon the history of borrowing and repayment, and the company's assets and liabilities. In general, large, well-established businesses have credit ratings. S&P provides increasing risk and declining credit ratings for investment-quality bonds ranging from **AAA** to **AA** to **A** to **BBB** (with "+" and "-" as sub-ratings or "notches" within these rating classes for relatively lower or higher risk, respectively). Moody's and Fitch provide comparable ratings, but Moody's uses different designations. A credit rating above BBB- is considered "investment grade" in which the probability for repayment of financial obligations is very good, and for default, low.

large majority of PGC market participants have credit ratings, although only slightly more than half are rated investment-grade. By contrast, a large majority of REPs do not have credit ratings. The REP market consists of a few well-capitalized companies that serve large numbers of customers, and a substantial number of smaller REPs that are not rated by the credit rating agencies and serve a smaller number of customers.

Senate Bill 7 required that the utilities restructure their organizations and, at a minimum, create separate companies that are under common ownership to carry out the regulated (TDU) and competitive (REP and PGC) functions. TXU is organized as separate subsidiary companies owned by TXU Corporation. Other utilities sold their competitive or regulated functions and today are largely, but not exclusively, either competitive companies or regulated companies. For example, the second largest TDU, CenterPoint, has no affiliation with a PGC or REP. American Electric Power (AEP) sold most of its REP and PGC operations and today is primarily a TDU in ERCOT. In cases where different functions are still under common ownership, the financial condition of the parent is affected by both the competitive and regulated operations. The next paragraphs describe the risks and financial conditions of each group of companies operating in the competitive ERCOT market.

With the introduction of competition in the production and sale of electricity to both wholesale and retail customers, the TDUs have become the only businesses still subject to extensive rate regulation. As part of their operations, TDUs are required to provide non-discriminatory transmission and distribution service. In this new environment, the primary risks that "wires" companies face are the likelihood that the Commission will not allow the companies' expenses (including the cost of capital) to be fully recovered in delivery rates, and the risk of a downturn in the local economy that would result in underrecovery of costs. Broadly speaking, the transmission and distribution of electricity is a low-risk business that should produce stable and predictable earnings and cash flows.

Provision of retail electricity has higher business and operating risks than those of the TDUs. REPs provide electricity to retail customers by purchasing wholesale electricity from PGCs in the ERCOT market, a market which currently features 75 actively competing REPs. Many of the REPs with large shares of the retail market are affiliates or former affiliates of large electric utility companies. At the start of retail competition, these companies inherited most of the customers in the service areas of the utilities from which the REPs were formed. These were known as "affiliated REPs" or "AREPs," although not all remained under common ownership with the formerly integrated utility. For example, Direct Energy acquired the affiliated REP business of AEP, however it is not affiliated with AEP today. Yet it remains the "affiliated REP" under the statute because it is the company that acquired the legacy customers from the integrated utility. The competitive REPs (those that were not affiliated with a formerly integrated utility) entered the competitive market without customers, and they have smaller market shares, but outnumber the affiliated REPs.<sup>76</sup> Several REPs that are affiliated with out-of-state or

<sup>&</sup>lt;sup>76</sup> Companies that are the affiliated REP for one service territory operate as a competitive REP in other service territories.

foreign utilities, such as Constellation Energy, Suez Energy, and Strategic Energy, have experienced noticeable growth since entering the retail market.

The large number of competitors in the marketplace highlights the fact that many companies can meet the Commission's technical and financial requirements to become certified in the state of Texas. Although the regulatory barriers to entry are relatively low, other qualities are also required to be successful in the market, such as access to capital resources, marketing savvy, capability in pricing electricity for retail customers in a volatile wholesale environment, and risk-management expertise. These characteristics play a crucial role in the financial health of the REPs. Access to capital is important for several reasons, in particular because the earnings and cash flows of a REP can be subject to variability, and risk management activities such as hedging require capital and do not always go as planned. The recent past has been particularly challenging for REPs, with significant increases in natural gas and electricity prices in 2005 leading six REPs to cease operations and transfer their customers to the Providers of Last Resort or other REPs.

PGCs operate as wholesale, independent providers of electricity, selling to REPs, integrated utilities not subject to retail competition, and ERCOT for services to help maintain the reliability of the electricity network. Many of the PGCs in ERCOT also own generating facilities in other markets, and their financial success is dependent on market rules and market conditions both in Texas and in other states. In many regions of the country, there was an abundant supply of electricity in the early years of this decade. This oversupply, the Enron bankruptcy, and other market disturbances resulted in the losses of access to capital markets and investor confidence for many PGCs.

As the economy has improved and demand for electricity and wholesale prices have risen, the confidence of the capital markets in IPPs has likewise improved, but some independent PGCs are still rated below investment grade, and problems do occasionally arise. For example, Calpine, one of the largest PGCs in ERCOT, filed a Chapter 11 bankruptcy proceeding in December 2005. Nevertheless, demand in ERCOT continues to grow, and projections indicate that future growth will also be strong.

A number of PGCs have announced plans to build new generating facilities to meet this demand, and they will need significant capital to do so. ERCOT reports plans for the addition of new generation facilities in two categories: projects not publicly announced, which consist of new plants that have not been publicly identified but for which the developers have begun the process for the identification of transmission facilities needed for the safe interconnection of the generating plant to the electric network; and publicly announced projects, which consist of new plants for which the developers have made a public announcement of their plans to build or have signed an agreement to interconnect the new plant to the ERCOT transmission network. The following table summarizes the most recent ERCOT report of new generation facilities.
	Wind Facilities (in megawatts)	Non-wind Facilities (in megawatts)	Total (in megawatts)
Publicly announced	2,761	14,139	16,900
Not publicly announced	14,468	13,679	28,147
Total	17,229	27,818	45,047

## Table 8: Proposed Generation in ERCOT

These plants, if completed, would begin operating between 2007 and 2011. One of the concerns with respect to these announcements is that TXU—the company in ERCOT with the largest share of the generation market—has the most aggressive construction plan, with over 9,000 MW of new coal generation planned. It is likely to be difficult for independent PGCs with poor credit ratings to raise the required capital to expand their capacity in ERCOT, so as to compete effectively with TXU. However, the recent announcement that Exelon is considering building a nuclear plant in Texas may be an indication that PGCs affiliated with out-of-state utilities have the financial capability and interest to compete in the generation sector in Texas.

The five largest TDUs that provide the highways for electricity traffic—AEP TCC, AEP TNC, CenterPoint, TNMP, and TXU ED—all have investment-grade credit ratings. Since March 2003, the ratings of the group have remained the same with the exceptions of TXU ED, which went from an S&P rating of BBB to BBB- on June 14, 2005, and TNMP, which went from BB+ to BBB on June 6, 2005, upon the closing of its acquisition by PNM Resources, Inc. (PNM). While the current outlooks for AEP TCC, AEP TNC, and CenterPoint are stable, PNM and TXU ED have negative outlooks. The negative outlook for PNM stems from operating concerns as well as increased capital spending for generation plant construction and the recent acquisition of the Twin Oaks generating plant. However, PNM has stated it will structure its financing to maintain its investment-grade credit rating. The negative outlook for TXU ED reflects the potential for increased risk to the consolidated TXU rating that could result from TXU's plan to build more coal-fired power plants, which will require an investment of over \$10 billion.

Approximately three quarters of the large REPs have credit ratings, or are affiliated with companies that have credit ratings. Of these, only one REP has a credit rating that is below investment grade. However, a majority of these companies have negative outlooks. Of the investment-grade companies, TXU Energy is S&P-rated BBB- with a negative outlook; Centrica, the parent company of Direct Energy, is rated A with a negative outlook; Constellation Energy is rated BBB+ with a positive outlook; FPL Group, the parent company of Gexa Energy, is rated A with a negative outlook; Great Plains Energy, the parent company of Strategic Energy, is rated BBB with a stable outlook; and Suez, the parent company of Tractabel Energy Services, is rated A- with a positive outlook. In some instances (such as Centrica and FPL Group), the Texas REP business is a relatively small part of the overall business for these companies, and the

rating is primarily a result of operations in other markets. Reliant Energy is the only large non-investment-grade REP. It is rated B with a negative outlook. The negative outlooks for these companies primarily reflect the uncertainties associated with market pricing, regulation, and the lower financial metrics and profiles of the companies in comparison to other entities with the same credit ratings. Reliant is active in other U.S. markets, but its Texas REP business is a major factor in its credit rating.

By contrast, the companies comprising the group of small REPs do not have credit ratings, either on their own or through affiliate relationships. However, these companies, such as Stream Gas and Electric and Green Mountain Energy, have established a visible presence in the retail market.

PURA §39.351 requires PGCs to register with the Commission and comply with certain reliability standards adopted by ERCOT. The market for PGCs, like the market for REPs, is bifurcated. A small group of large market share PGCs provides approximately 85% of generation supply, and almost all are credit-rated entities. However, this group is not as financially strong as the comparable REP group discussed above, because approximately 35% of the PGCs have below-investment-grade credit ratings. Moreover, several PGCs in this group currently have negative outlooks from the credit rating agencies. The group of smaller market share PGCs is financially stronger than the small REP group discussed above, as evidenced by the large number of credit ratings (although a number of them are not investment grade). There is no clear uptrend or downtrend in the historical credit ratings of PGCs over the last several years. Thus, this category is riskier and not as financially robust as the TDU or large REP categories.

# IV. ASSESSMENT OF OTHER SENATE BILL 7 GOALS AND BENEFITS

# A. CUSTOMER PROTECTION / COMPLAINT ISSUES

The Commission's Customer Protection Division has experienced a steady increase in the number of complaints it has received and handled related to electric service from the beginning of competition in 2002.<sup>77</sup> Complaints peaked during July and August 2003. Then in FY 2004, the Customer Protection Division handled more than 11,000 electric complaints. This is an average of approximately 2,750 complaints per quarter. Complaints declined during FY 2005 to just over 7,800 electric complaints, or about 1,950 complaints per quarter. Electric complaints rose again in FY 2006, to 10,652, or 2,663 per quarter.



## **Figure 18: Total Complaints Received**

Source: PUC Customer Protection Division

<sup>&</sup>lt;sup>77</sup> Complaint statistics are compiled from the Customer Protection Division's complaint database. Mining the data for complaint trends serves as a barometer for gauging company behavior and its effect on their customers or their industry. As a management tool, mining data to reveal company-specific trends may lead to meetings with companies and discussion of issues identified in the complaint database. It is also used to alert Commission Staff of the need for possible enforcement actions.

The majority of electric complaints were billing-related, which represented 51% of the total. Other major categories were complaints about discontinuance of service, at 17%, and provision of service, at 16%.



Figure 19: Composition of Electric Complaints Received, September 2004 - August 2006

Source: PUC Customer Protection Division

# **B. Renewable Energy Mandate**

Texas achieved two significant renewable energy milestones in 2006. First, the state exceeded the 2,880 MW goal for renewable energy that had been established in 1999 by Senate Bill 7, a goal that the Legislature had mandated be reached by 2009. Second, Texas surpassed California as the state with the greatest amount of installed wind power. On a worldwide scale, the only countries that have more wind power than Texas are: Germany (18,428 MW), Spain (10,027 MW), and Denmark (3,122 MW).<sup>78</sup>

Wind-powered resources account for 78% of the state's 3,263 MW of installed renewable capacity, and 97% of the 2,462 MW of capacity installed since the enactment of Senate Bill 7. Most of the new wind capacity added since the Commission's last report to the Legislature has been in the Abilene-Sweetwater area.

About 2.1% of the electricity generated in Texas during 2006 came from renewable energy resources, up from 1.5% for all of 2005.<sup>79</sup> Within the ERCOT power region, renewable resources provided 2.1% of peak-period generation during 2006 (up from 1.5% in 2005), and 3.2% of off-peak generation (up from 2.2% in 2005). The figure

<sup>&</sup>lt;sup>78</sup> European Wind Energy Association, statistics page at <u>http://www.ewea.org/index.php?id=180</u>.

<sup>&</sup>lt;sup>79</sup> *Electric Power Monthly*, Energy Information Administration (Mar. 2006 and Aug. 2006).

below illustrates the growth both in installed renewable capacity and in electricity production from renewable resources since 2002.



Figure 20: Growth in Renewable Energy Generation and Capacity Since 2002

The mechanism that the Legislature adopted to meet the renewable energy goal was a system for earning and trading Renewable Energy Credits (RECs). With this mechanism, REPs must obtain RECs for a portion of their energy sales. The RECs that were needed to meet the goal represented about 1% of the electricity sold to retail customers in 2004 and 2005, and about 1.7% in 2006.<sup>80</sup> Despite this increase, the impact of the statewide Renewable Portfolio Standard (RPS) mandate on customers' bills actually fell in 2006 because of a sharp drop in renewable energy prices.<sup>81</sup> For a typical residential customer using 1,000 kWh of electricity per month, the impact of the renewable energy goal was equivalent to about 12 cents per month in 2005, and about 7 cents per month for 2006.<sup>82</sup>

The REC Trading Program is also designed to permit REPs to offer readily-verifiable renewable energy products, so that consumers' preferences for renewable energy can be met. Retailers buy and use RECs to satisfy their obligations under the RPS mandate, but they may also use RECs to provide customers with green power (retail services that use

<sup>82</sup> Analysis assumes market price of \$12.30 per REC (MWh) in 2005 and \$4 per REC in 2006. *Monthly Market Update*, Evolution Markets Inc. (Jul. 2005 and Jul. 2006). <u>http://www.evomarkets.com/assets/mmu/mmu\_rec\_jul\_05.pdf</u> and <u>http://www.evomarkets.com/assets/mmu/mmu\_rec\_jul\_06.pdf</u>.

<sup>\*</sup> Projected

<sup>&</sup>lt;sup>80</sup> REC Trading Program database. Sales figures for 2006 are projections based on data from January through June.

<sup>&</sup>lt;sup>81</sup> This calculation assumes that the cost to the REPs is passed on to customers. However, there is no requirement in law or Commission rules to pass the costs or this reduction on to customers.

more renewable energy than required by the RPS). Customer demand for green power amounted to 951,331 MWh in 2005, equivalent to about 310 MW of generating capacity.

Concerns have been raised that Texas RECs have been used for purposes outside the state, but REC data indicate that such concerns have no empirical basis. Virtually all Texas RECs that have been created since the program began in 2001 have been used either to satisfy Texas RPS obligations, or to authenticate green power sold to customers in Texas. The largest sellers of green power to Texas customers in 2005 were Austin Energy, Constellation NewEnergy, Green Mountain Energy, Reliant Energy, and TXU Energy, which together accounted for 99% of the voluntary REC market.



Figure 21: Portion of ERCOT Electricity Demand Met by Renewable Resources

Source: ERCOT data archives; lines represent 7-day moving averages.

The original renewable energy goal contained in Senate Bill 7 presumed the existence of 880 MW of existing capacity. Since that time, however, a number of small pre-1999 generators have been retired, amounting to 33 MW. In accordance with Commission rules, this will require an increase in the RPS requirement in 2007 to recapture the lost capacity.

Development of renewable energy projects continues in Texas. According to ERCOT, developers of renewable energy projects have signed agreements with transmission providers to connect an additional 1,700 MW of wind generation facilities to the ERCOT transmission network over the next five years.

The Legislature increased the state's renewable energy goal in 2005 with the enactment of Senate Bill 20. As amended by Senate Bill 20, PURA 39.904(a) directs that the cumulative installed renewable capacity in this state shall total 2,280 MW by January 1, 2007; 3,272 MW by January 1, 2009; 4,264 MW by January 1, 2011; 5,256 MW by January 1, 2013; and 5,880 MW by January 1, 2015. Further, the Commission is directed to establish a target of 10,000 MW by January 1, 2025. The legislation includes a target of 500 MW from renewable resources other than wind power. In addition, Senate Bill 20 requires the Commission to designate CREZs to expedite transmission planning.

The Commission's activities with respect to CREZ designations are discussed in Section II.A.1 of this report. A separate rulemaking addressing other requirements of Senate Bill 20 is scheduled for completion before the summer of 2007.

# C. ENERGY EFFICIENCY

The Public Utility Commission administers an energy efficiency program under PURA §39.905 designed to improve utility customers' energy use and meet a statutory goal for energy efficiency. This program is operated by the utilities and funded through rates. In 2005, utilities spent roughly \$78 million on this program. The goals of the PURA energy efficiency program are to:

- achieve energy savings through incentive programs conducted by electric utilities in a market-neutral, nondiscriminatory manner;
- give all customers access to energy efficiency alternatives that allow them to reduce energy consumption and reduce energy costs; and
- acquire cost-effective energy efficiency equivalent to at least 10% of each electric utility's annual growth in demand.

The Commission adopted rules to implement the energy efficiency program in 2000, and amended them in 2004.<sup>83</sup> Legislation was enacted in 2005 to modify the energy efficiency program in several respects:

<sup>&</sup>lt;sup>83</sup> PUC SUBST. R. 25.181, relating to Energy Efficiency Goal; PUC SUBST. R. 25.183, relating to Reporting and Evaluation of Energy Efficiency Program; and PUC SUBST. R. 25.184, relating to Energy Efficiency Implementation Project.

- The Commission was directed to adopt specific market-transformation programs, including energy-smart schools and landscaping programs for energy efficiency.
- Utilities were authorized to use energy efficiency funding for research and development to foster improvements and innovation in energy efficiency technology and program design.
- The Commission was directed to have the utilities fund low-income energy efficiency programs.

Savings reported by the utilities for the energy efficiency program continue to meet the statutory goal. Energy efficiency measures implemented during calendar year 2005 saved nearly 500,000 MWh of energy, and the TDUs, which were responsible for administration of the energy efficiency program, exceeded their demand reduction goals by 27%. The utilities' program expenditures of \$78 million in 2005 will provide customers a total energy cost savings of \$290 million over the ten-year project life of the efficiency measures.

During FY 2006, the Commission also sanctioned an evaluation of calendar year 2003 and 2004 energy efficiency programs by a third party. The Commission hired the firm Summit Blue to evaluate the energy efficiency programs of six utilities, covering the bulk of the reported energy savings.<sup>84</sup>

On September 8, 2006, the measurement and verification expert, Summit Blue, submitted a final report which noted that the utilities cumulatively exceeded the goal of a 10% reduction in growth in demand. The measurement and verification review included an audit of the savings reported by the utilities, the programs' delivery methods, and savings claims based on program databases, paper records, and interviews. Based on the Summit Blue audit, approximately 100% of the claimed savings were verified for each program year.

Program Year	Goal (MW)	Achieved (MW)	Results (MW)	Achieved (MWh)
2003	136 MW	150 MW	Goal + 10%	368,688 MWh
2004	147 MW	192 MW	Goal + 30%	447,606 MWh

 Table 9: Evaluation of Energy Efficiency Programs

The report noted that the most comparable study was a 2004 review of programs administered by the California utilities, which verified 96% of the energy savings goals.

<sup>&</sup>lt;sup>84</sup> The following six utilities were evaluated: American Electric Power, CenterPoint Energy, Entergy Gulf States, Texas-New Mexico Power, TXU Electric Delivery, and Xcel Energy.

The results were similar at the utility level; all utilities' reported savings were within 2.5% of the reported results.

Summit Blue also evaluated the process by which utilities acquire energy efficiency services and reached the following conclusions:

- The 10% ceiling for administrative expenses for the utilities has not proven burdensome, but it does not allow for significant program enhancements.
- The program incentives are more than sufficient to encourage participation.
- A small business set-aside has helped diversify sponsor representation and encourage participation by local companies.
- Protocols should be established for savings estimates for the Market Transformation Programs.
- The current first-come, first-served enrollment process works generally well, but does not allow for equal access to program funds among all potential sponsors.
- Cooperation among the utilities has generally been quite good.
- A multi-utility program database developed by Frontier Associates to record and report savings has been a key feature for helping keep program administrative costs within the 10% cap.
- The utilities' program staffs are responsive and helpful with both technical and administrative issues.
- Program outreach and marketing have been very successful.
- The training offered by the utilities has been effective and well received.

With the enactment of legislative changes relating to energy efficiency, the completion of the Summit Blue evaluation, higher energy prices in late 2005 and throughout 2006, and other developments relating to energy efficiency, the Commission initiated a review of the energy efficiency program in late 2006. Future issues to be addressed by the Commission include the CenterPoint settlement energy efficiency provisions, Commission decisions on funding of low-income weatherization and Hard-to-Reach programs, and the rule and activities for pilot projects initiated for new programs from the 2005 Legislative Session.

# V. EMERGING ISSUES

# A. SYSTEM HARDENING

Commission Staff initiated a project to identify ways to improve electric and telecommunications infrastructure, and to minimize the utilities' downtime occurring as the result of Gulf Coast hurricanes.<sup>85</sup> To accomplish this, Staff conducted industry workshops at the Commission as well as town hall meetings in the Houston, Beaumont, and Corpus Christi areas. Additional information was obtained directly from the utilities as well as interested parties. The final report concluded with three recommendations for utilities along the Gulf Coast and nine recommendations for all of the utilities in the state. Eight recommendations will ultimately require rulemakings over the next 12 months to define the requirements thoroughly for the utilities.

Five of the recommendations focus on the inspection and operation of overhead facilities to ensure that control of vegetation and pole attachments, along with proper maintenance, are included in the utilities' procedures. Three of the recommendations encourage modernization of the electric grid with intelligent devices and the use of underground distribution facilities. The siting of new substations is addressed in one recommendation. ERCOT is investigating possible interconnection points along the interface between ERCOT and SPP for emergency operation if needed during future hurricane restoration efforts.

# **B. DEMAND RESPONSE**

Demand response, the ability of customers to reduce usage in response to high prices or grid conditions, will play an increasing role in the electricity market in the coming years. Under the energy-only resource adequacy mechanism the Commission endorsed, demand response can provide the following benefits:

- provide additional operating reserves;
- avoid or reduce the impact of system emergencies;
- increase the range of potential products that REPs can sell;
- mitigate the market power of generators; and
- provide additional means for retail customers to respond to high prices; and
- "shave" peak prices.

<sup>&</sup>lt;sup>85</sup> PUC Investigation of Methods to Improve Electric and Telecommunication Infrastructure that Will Minimize Long Term Outages and Restoration Costs Associated with Gulf Coast Hurricanes, Project No. 32182 (pending).

In times when reserve margins are tight, having customers who can reduce usage at peak times adds additional security to the system. For instance, under an energy-only market, spot electricity prices in ERCOT markets can increase sharply, reaching over \$1,000 per MWh when almost all available generation is being deployed to meet "superpeak" demand. These high prices would signal to retail customers that ERCOT has very little available generation to maintain system reliability, and could prompt customers that have the flexibility, such as customers running oil and gas pumping jacks, commercial freezers, and residential water heaters, to voluntarily reduce their energy use. Large retail customers participate in operating reserve markets today, through voluntary curtailments, and the Commission and ERCOT are exploring additional opportunities for loads to provide reserves to assist ERCOT in maintaining system reliability. Enhancing the opportunities for demand response can provide improved levels of reliability for customers who do not participate in the programs and financial benefits for customers who do.

Some customers have some ability to respond to high prices by reducing usage at times when the price of electricity rises to a high level. This option may be attractive to additional customers, if developments in metering allow smaller customers to have their consumption metered at intervals shorter than one month and if they take advantage of retail prices that are based on wholesale prices. For ERCOT's settlement system to allow smaller customers to respond readily to spot market prices, advanced metering will be required. When advanced meters are deployed, REPs will have the chance to offer demand response products to smaller customers, which will in turn allow customers to have more control over their electric bills. The Commission has opened a rulemaking project on advanced metering, which is discussed in Section II.A.1 of this report.

Advanced metering will reinforce the economic and reliability benefits of retail competition. Advanced meters will allow REPs to offer a wider range of products, allowing customers to adjust their electricity usage in response to prices and save on their electric bills by running some appliances at off-peak times. A wider range of demandside products that REPs will be able to offer should increase the amount of price-responsive demand available to ERCOT in real-time to maintain reliability.<sup>86</sup>

Increasing the ability of smaller customers to respond to high prices can also help address one of the biggest challenges facing the Commission in overseeing the ERCOT wholesale market: demand response can mitigate the exercise of market power in ERCOT spot markets (*e.g.*, ancillary services capacity and balancing energy). When loads can easily and promptly respond to high prices, holders of large generation portfolios will be less likely to sustain artificially high prices through market manipulations, resulting in greater public confidence that high prices in the ERCOT spot markets are a function of genuine scarcity, not market power abuse.

<sup>&</sup>lt;sup>86</sup> It is expected that high wholesale prices will generally correspond to reliability events, as high prices will be an indication of a shortage of generation capacity to serve the aggregate customer load.

The Commission has opened two projects to address demand response issues and has plans to open more. Project No. 32853, *Evaluation of Demand Response Programs in the Competitive Electric Market*, was established to evaluate different aspects of demand response, specifically to investigate demand response programs and barriers to the implementation of those programs. Project No. 33457, *PUC Rulemaking Concerning a Demand Response Program for ERCOT Emergency Conditions*, was established to discuss an ERCOT emergency program that would be deployed as a preliminary step to reduce system load before initiating firm load shedding in the ERCOT Emergency Electric Curtailment Plan, which may prevent the shedding of firm load. Through these projects, as well as the new projects it intends to open in the near future, the Commission will investigate and take part in the development of new demand response programs.

# C. CALCULATION OF THE LOW-INCOME DISCOUNT

PURA §39.903 provides for a rate reduction (or "discount") program for eligible lowincome electric customers to be funded by the SBF. As discussed in Section II.F, no appropriations were made for this program for FY 2006 and FY 2007. Therefore, as discussed in Section II.A.1, the Commission made modifications to the rule governing the rate reduction program to reflect the changes in statute made by the 79<sup>th</sup> Legislature, and to account for the possibility of varying levels of appropriations. However, new issues have emerged which will affect the calculation of the discount should future appropriations provide for the return of the program. The Commission therefore plans to re-open the rule to address the calculation of the rate reduction.

PURA §39.903(h) describes a customer's benefit from the rate reduction program as a reduced rate to be discounted off the standard retail service package (namely, the POLR rate) or the price to beat, whichever is lower; and in a separate sentence, as a reduced rate that is at least 10% and up to 20% lower than the amount the customer would otherwise be charged. The statute requires that the low-income discount be set at a level that will provide a 10% to 20% rate reduction on eligible customers' bills. However the statute allows the Commission to reduce the rate below 10% if the fee is set at 65 cents per MWh or if the Commission determines that appropriations are insufficient to fund the 10% rate reduction.

The Commission currently has rules further specifying the calculation of the rate reduction. Based on the statute and the rule, the discount has been calculated based on the price to beat for each TDU service territory. The price to beat has historically been lower than the POLR rate, and thus has historically been the rate at which most residential customers have been enrolled. The discount has been a fixed-rate, cents per kWh discount on the customer's bill, and has changed as the price to beat has changed. Therefore, the discount calculation has met both directives of the statute: to be based off the lower of the price to beat or standard offer rates, and to equal a percentage lower than the amount the customer would otherwise be charged. However, the price to beat will expire at the end of 2006. This expiration means that the POLR rate will be the basis of the discount. It is not clear that such a rate would meet the intent of the statute. In the

spring and summer of 2006, the Commission conducted a rulemaking to revise the POLR rule, which included the revision of the POLR rate.<sup>87</sup> Under the amended POLR rule, the POLR rates will change hourly. Although this rate was determined with public input to be the most appropriate rate for POLR service, the Commission does not expect that a discount calculation based upon the POLR rate would reflect the statutory intent. Additionally, budgeting for a highly-variable price would be challenging, and customers would have a difficult time understanding how the discount is calculated. This would create customer confusion as well as extra work for the Commission, the program administrator, and REP call centers. Therefore, the Commission intends to seek comments on a proposal to revise the discount calculation to result in a flat discount per customer per month, with adjustments for peak and off-peak seasons. Under the intended proposal, the discount would be calculated based upon historical or expected rate levels, appropriations levels, and enrollment projections for the fiscal year. The Commission expects that the rulemaking will result in a revised discount calculation that more appropriately reflects the intent of the statute and the current market structure.

# **D.** ALTERNATIVE TRANSMISSION MODELS

Existing transmission facilities in Texas are, with minor exceptions, constructed and operated by electric utilities, and the costs of owning and operating the facilities are recovered through rates that are regulated either by the Commission, FERC, or through retail rates set by a municipal utility or electric cooperative. Several companies have expressed an interest in constructing transmission facilities using a different regulatory approach. The Commission may have some discretion to adopt innovative transmission rules, but the adoption of legislation on this subject would clarify the rules for companies that are considering making significant investment in new transmission facilities.

Under current rules, an electric utility that builds transmission facilities is subject to rules that:

- require the utility to obtain Commission approval for the new facility, through obtaining a CCN;
- require the utility to provide open-access service to eligible transmission service customers;
- permit the utility to recover the cost of the facilities through regulated rates; and
- permit the utility to use eminent domain to obtain easements for the transmission facilities.

Some large customers have built transmission facilities on industrial sites and have interconnected their privately-owned facilities to the utility network, because, under this arrangement, they have better control over the facilities on the site and access to the site. This is an option that is very limited, because the owner of the transmission facility may

<sup>&</sup>lt;sup>87</sup> Project No. 31416, *loc. cit.* 

not charge another customer for the use of such a facility without becoming subject to the rules applicable to utilities.

There has been interest in building transmission under a different set of rules. A power generation company might, for example, be willing to build and operate transmission facilities at its own expense (with no support from regulated rates) to connect to the transmission grid, without incurring the obligation to provide open-access to other entities. Such an arrangement might, for example, permit one or more generation companies that are outside of ERCOT to connect their facilities to the ERCOT transmission network at their own expense, without running the risk that they would be obligated to provide service to other customers. A similar transmission arrangement might permit a group of wind generators to build transmission to move the power they generate from West Texas to a location closer to population centers in East and Central Texas. Developers might also be interested in building merchant transmission connections between ERCOT and other power regions (the eastern or western United States or Mexico), where the interconnections are limited today.

One of the uncertainties with respect to the construction of long transmission facilities is whether a power generation company could use eminent domain to obtain an easement for the facilities. Eminent domain might not be necessary for short transmission facilities, because the company that seeks to build those facilities would presumably have a small number of land owners to deal with. For a longer line, the number of land owners could be significant, and acquiring easements could be difficult and expensive.

The Commission believes that the Legislature should consider whether to authorize the construction and operation of transmission facilities connecting to the ERCOT transmission network, using a different model, one in which the risks associated with building and owning the facilities would be borne by the company that proposes to build them. Analogizing to the existing open-access rules, a company that is interested in building transmission facilities might have rights based on an open-interconnection rule, in which merchant transmission companies would have the right to interconnect privately-funded transmission facilities to the utility transmission network. If such an approach is considered, the following elements would be necessary for the open-interconnection rules:

- The merchant transmission company would have to build, operate, and maintain the facilities to standards prescribed by ERCOT.
- The merchant transmission company would have to provide information to ERCOT concerning the design of the facilities and the characteristics of any generation facilities that were interconnected to it.
- ERCOT would have the right to deny interconnection, based on the impact of the transmission facility and interconnected generation facilities on the ERCOT network, or require the transmission company to bear the cost of transmission improvements needed for a safe and reliable interconnection that does not adversely affect the capability of the existing ERCOT network.

- The merchant transmission company would be subject to operating rules prescribed by ERCOT, including rules relating to the provision of operating information for the generation facilities interconnected to it.
- The merchant transmission company would be subject to either rules or preconstruction review related to avoiding environmentally sensitive areas and conflicting land uses.
- The merchant transmission company would not be subject to open-access rules.

For any such merchant transmission arrangement, the Legislature would also have to address the issue of eminent domain. The taking of private property for what might be regarded as private commercial purposes raises significant constitutional and policy issues, but not providing for eminent domain is likely to significantly limit the usefulness of the merchant transmission model.

# **E. AIR PERMITS FOR ELECTRIC GENERATORS**

As the Texas economy grows and older power plants are retired, new sources of supply and a more responsive demand profile among electric customers will be needed to ensure that supply is adequate to meet consumers' demand for electricity. The market rules in ERCOT and the legislative encouragement of advanced metering should encourage the construction of generating facilities and foster demand response programs that will be needed to meet customers' needs. One of the challenges for developers of new generation facilities in Texas will be complying with air emission rules, particularly obtaining the necessary air emission permits from the Texas Commission on Environmental Quality (TCEQ). While today the Public Utility Commission has no role in the air permit process, it believes it could perform a useful role, to ensure that the TCEQ considers the state's need for new generation facilities in deciding whether to grant an air permit.

Environmental issues have become increasingly important in developing new power plants, nationally and in Texas. The U.S. Environmental Protection Agency has designated Dallas-Fort Worth, Houston-Galveston, and Beaumont-Port Arthur as not meeting the national standards for ozone, and other areas of the state are close to exceeding the limits for ozone and could be designated as not in attainment with the ozone standards. In addition, higher standards for sulfur-dioxide and mercury emissions have been adopted. A number of states have adopted programs to reduce emissions of greenhouse gases, and there is some likelihood that national legislation on this subject will be considered in the near future. Higher standards for these emissions present challenges, in obtaining air permits from the TCEQ, to developers planning to build thermal power plants.

In issuing an air permit, the TCEQ considers the impact of the plant on air quality, but it does not explicitly consider the needs of the state for additional sources of electricity. The Public Utility Commission believes that the TCEQ should consider this need in

deciding whether to issue an air permit, and that the Public Utility Commission should be permitted to provide information to the TCEQ on the state's energy needs in a permit application proceeding.

# VI. LEGISLATIVE RECOMMENDATIONS

## A. LEGISLATIVE RECOMMENDATIONS

## 1. Procedural Recommendations

## a. Confidentiality of Enforcement Investigations

The Commission has expended significant resources over the past biennium to enhance its investigations and prosecutions in telecommunications and electricity markets in Texas. The Commission believes that vigorous, fair, and appropriate enforcement of Texas statutes and Commission rules is critical to ensuring well-functioning marketplaces and a level playing field for companies competing for customers.

The Commission is concerned that the release of information related to investigations while those investigations are underway will hamper the ability of the agency to perform its enforcement duties and unfairly impugn the business practices of telecommunications or electric providers before all the facts have been determined.

Specific areas of concern about the premature release of information related to enforcement investigations include:

- Public disclosure may discourage company employees, competitors, or contractors from acting as "whistle-blowers" because specific allegations may be traced to individuals who could face retribution.
- Public disclosure may result in a company (either the company directly involved or a company that may be engaged in similar behavior) discovering the Commission's legal strategy or analysis, which could enable the company to mask their behavior or circumvent the law, ultimately making prosecution more difficult.
- Public disclosure may create a more antagonistic and litigious atmosphere between the Commission and the company involved during the early stages of an investigation when cooperation can facilitate the Commission's efforts to determine the accuracy of basic facts and to determine the scope, severity, and nature of a potential violation.
- Public disclosure may create an unfair presumption of a company's guilt that may not be supported by the actual facts or evidence and that may be difficult to remedy once the investigation is complete. The company's reputation may be unfairly harmed, which can negatively affect the company, its employees,

its investors, and the public's confidence in the company and in the operation of the competitive market.

Additionally, the Commission has retained an IMM for the ERCOT wholesale electric market, pursuant to the requirements of PURA §39.1515. The IMM is responsible for monitoring the wholesale electricity market in ERCOT to detect and prevent market manipulation strategies. The IMM will perform investigations to determine whether market manipulation or a violation of the Commission's or ERCOT's rules has occurred, and is required to report violations or potential violations to the Commission. The Commission has also agreed to serve as a hearing body for the ERCOT region in enforcing national reliability standards, and federal regulations may require that information pertaining to alleged violations of these standards remain confidential.

The IMM relies on methodologies and quantitative tools to assess the operation of the market and to identify conduct or practices that may violate market rules. These tools may include indices, screens, reports, computer models, and other programming tools that permit the IMM to evaluate a large volume of market information effectively. The methodologies and quantitative tools are critical to market monitoring, and their disclosure could undermine the IMM's monitoring efforts. Because the Commission has access to the information used by the IMM, the Commission is concerned that the analysis, investigations, and monitoring tools used by the IMM may be subject to release under the Public Information Act. Public availability of this information could provide wholesale market participants with access to information that would enable them to mask rule violations and other harmful conduct from the IMM.

Section 552.101 of the Public Information Act exempts from disclosure information that is considered confidential by law. The enabling statutes of many state agencies with investigative authority, enforcement obligations, and administrative penalty assessment authority over licensees of the agency provide that investigation files are confidential as a matter of law. For example:

- Article 581-28 of the Securities Act provides that "all information of every kind and nature received in connection with an investigation and all internal notes, memoranda, reports, or communications made in connection with an investigation" by the State Securities Board are considered confidential.
- Section 531.1021 of the Health and Safety Code provides that all information and materials compiled by the Office of Inspector General of the Health and Human Services Commission as part of an audit or investigation are confidential and not subject to disclosure under the Public Information Act.
- Section 773.0612 of the Health and Safety Code provides that reports, records, or working papers used or developed in an investigation by the Texas Department of State Health Service (now part of the Texas Department of Health) relating to patient care or emergency medical service personnel are confidential.
- Section 142.009 of the Health and Safety Code provides that investigation reports, records, and working papers used or developed in an investigation of

home and community support services agencies are confidential and may not be released to the public, except in certain circumstances.

- Section 241.051 of the Health and Safety Code provides that all information and materials obtained or compiled by the Texas Department of Health in an investigation of a hospital are confidential.
- Section 801.207(b) of the Occupations Code provides that investigation records of the Texas State Board of Veterinary Medical Examiners are confidential, including investigation records relating to a complaint that is ultimately found to be groundless.
- Section 205.3544 of the Occupations Code provides for confidentiality of complaints filed with the Texas State Board of Acupuncture Examiners.
- Section 201.206 of the Occupations Code provides that investigation files of the Texas Board of Chiropractic Examiners are confidential, privileged, and not subject to release.

The Commission believes that to enhance confidence in the electric and telecommunications markets and in the Commission's enforcement activities, the Legislature should make the Commission's and the IMM's investigation records and the IMM's market monitoring tools confidential as a matter of law.

### Sec. 15.020. INVESTIGATIONS AND INVESTIGATORY MATERIALS.

(a) The executive director shall conduct investigations as the executive director considers necessary to prevent or detect the violation of this title or a rule or order adopted under this title.

(b) "Executive director" means the executive director of the commission or the executive director's designee.

(c) "Wholesale electric market monitor" means the entity established in accordance with Section <u>39.1515.</u>

(d) "Investigation" means an inquiry by the executive director or the wholesale electric market monitor into specified acts or alleged acts that a person or other entity subject to the jurisdiction of the commission has engaged in, is engaging in, or is about to engage in that may violate this title, a rule or order adopted under this title, the rules of an independent organization, or reliability standards adopted under federal law. For purposes of this section, complaints made pursuant to Section 15.051 and 15.052 are not considered investigations.

(e) All information of every kind and nature received in connection with, that formed the basis of, or was created or compiled in the course of an investigation conducted by the executive director, a regional entity, as defined in Federal Energy Policy Act of 2005 (16 USC §8240), or the wholesale electric market monitor are confidential and shall not be disclosed to the public except under order of the commission or court for good cause shown.

(1) At the discretion of the executive director, this information may be disclosed to the person or entity that is the subject of the investigation.

(2) Nothing in this section shall be interpreted to prohibit or limit the publication of rulings or decisions of the commission, nor shall the limitations of this subsection apply if disclosure is made, in the discretion of the executive director, as part of an administrative proceeding or a civil or

<u>criminal action to enforce this title provided that specific trade secrets or other information that is</u> <u>otherwise privileged or confidential by statute or judicial decision remains confidential.</u>

(3) A notice and report issued by the executive director in accordance with Section 15.024, the pleadings in an administrative proceeding, and a final decision or order by the commission shall not be considered confidential provided that specific trade secrets or other information that is otherwise privileged or confidential by statute or judicial decision remains confidential.

(4) The executive director may disclose any confidential information in the executive director's possession to another governmental or regulatory authority, the office of attorney general, the state auditor's office, or federal, state, or local law enforcement agencies.

Sec. 39.1515. WHOLESALE ELECTRIC MARKET MONITOR.

(a)-(h) No change

(i) Any methodologies, tools, indices, screening criteria, measures, forecasts, risk assessments, or formula developed or used by the market monitor for the purposes of carrying out its responsibilities under this section, including conducting investigations, are confidential and are not subject to disclosure under Chapter 552, Government Code.

(j) For purposes of this section, "investigation" has the same meaning as in Section 15.020.

## b. Administrative Penalties

PURA \$15.023 provides authority to the Commission to enforce Commission rules and PURA, and to assess administrative penalties for violations of PURA or Commission rules. The Commission is concerned that certain provisions in this section may unintentionally impede the ability of the Commission to perform that role. These provisions include:

- The statute currently appears to mandate referral of enforcement proceedings to SOAH. While the Commission relies on, and will continue to rely on, the expertise of SOAH in most enforcement proceedings, the Commission is concerned that some cases may warrant more expedited action by the Commission than referral to SOAH can provide.
- The statute also prohibits the Commission from assessing administrative penalties if a violation was accidental or inadvertent and the company remedies the violation within 30 days of receiving the notice of intent to assess administrative penalties, except for violations of Chapters 17, 55, or 64 of PURA and PURA §39.157(a).<sup>88</sup> The Commission is concerned that this provision does not provide companies sufficient incentives to comply with PURA and Commission rules. The Commission believes that, consistent with the current statutory treatment of violations of PURA Chapters 17, 55, and 64 and §39.157(a), whether a violation was accidental or inadvertent and whether the company remedies the violation should be considered as factors in

<sup>&</sup>lt;sup>88</sup> PURA Chapters 17 and 64 relate to customer protections. Chapter 55 relates to certain regulations of telecommunications services. PURA §39.157(a) relates to electric market power abuses.

determining the amount of the administrative penalty. The Commission does not believe that these factors should be used to exempt violations from administrative penalties.

The Commission recommends changes in PURA to address these concerns.

#### Sec. 15.024. ADMINISTRATIVE PENALTY ASSESSMENT PROCEDURE.

(a)-(b) No change

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

(d)-(e) No change

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

(g) No change

#### Sec. 39.157. COMMISSION AUTHORITY TO ADDRESS MARKET POWER.

The commission shall monitor market power associated with the generation, transmission, (a) distribution, and sale of electricity in this state. On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or civil penalties as necessary to eliminate or to remedy the market power abuse or violation as authorized by Chapter 15, by imposing an administrative penalty as authorized by Chapter 15, or by suspending, revoking, or amending a certificate or registration as authorized by Section 39.356. Section 15.024(c) does not apply to an administrative penalty imposed under this section. For purposes of this subchapter, market power abuses are practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion. A violation of the code of conduct provided by Subsection (d) that materially impairs the ability of a person to compete in a competitive market shall be deemed to be an abuse of market power. The possession of a high market share in a market open to competition may not, of itself, be deemed to be an abuse of market power; however, this sentence shall not affect the application of state and federal antitrust laws.

(b)-(i) No change

## 2. Substantive Recommendations

## a. Assessment of Generation Market-Share

The generation market-share limit in PURA §39.154(a) provides that a PGC may not own and control more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region. This provision limits the ability of a PGC to exercise market power in the supply of electricity to a power region such as ERCOT. If it is determined that a PGC exceeds the 20% threshold, the PGC would be required to file a market power mitigation plan with the Commission pursuant to PURA §39.156. In its mitigation plan, the PGC may propose any reasonable method for reducing its ownership and control of installed generation capacity.

The Commission is concerned that the phrase "own and control" is not broad enough to identify all of the types of arrangements that could result in market power.

Market power is an issue over a range of time horizons. The ability to control the output of a generating plant without owning it is a market power issue in short time horizons. It has become common in the wholesale power market for generation owners to contract with other parties in the market for the output of their generating units. Such contracts may provide for "dispatch" control, which means that the buyer of a generator's output can determine how much power will be produced and when. In addition, the buyer is free to offer the power for resale to other parties, including the independent system operator, such as ERCOT, at whatever price it chooses. These contracts transfer the opportunity to use and sell the output of a plant for the period specified in the contract. For this reason, the PGC that acquires control under such a contract has the ability to produce or not and to establish its price for the output of the plant. Because PGCs can contract with each other in this manner, it is quite possible for a PGC to own and control less than 20% of the installed generation capacity, but control *more* than 20% through a combination of ownership and contracting.

Ownership is also a market power issue. A company that owns a large share of the generation plants in the market is likely to be able to exercise market power over long time horizons. Although the company may by contract relinquish control of some of its plants in the short term, its long-term control of the plants through ownership may dissuade other companies from building and owning plants in competition with the company.

To address this concern, the Commission recommends that the "own and control" criterion should be changed to "own or control, or any combination thereof," in PURA §39.154(a) and other similar provisions.

### Sec. 39.152. QUALIFYING POWER REGIONS.

(a) The commission shall certify a power region if:

#### Scope of Competition in Electric Markets in Texas

(1) a sufficient number of interconnected utilities in the power region fall under the operational control of an independent organization as described by Section 39.151;

(2) the power region has a generally applicable tariff that guarantees open and nondiscriminatory access for all users to transmission and distribution facilities in the power region as provided by Section 39.203; and

(3) no person owns and <u>or</u> controls, <u>or any combination thereof</u>, more than 20 percent of the installed generation capacity located in or capable of delivering electricity to a power region, as determined according to Section 39.154.

(b)-(c) No change

(d) For a power region outside of ERCOT, a power generation company that is affiliated with an electric utility may elect to demonstrate that it meets the requirements of Subsection (a)(3) by showing that it does not own and or control, or any combination thereof, more than 20 percent of the installed capacity in a geographic market that includes the power region, using the guidelines, standards, and methods adopted by the Federal Energy Regulatory Commission.

(e) No change

#### Sec. 39.154. LIMITATION OF OWNERSHIP OF INSTALLED CAPACITY.

(a) Beginning on the date of introduction of customer choice in a power region, a power generation company may not own and or control, or any combination thereof, more than 20 percent of the installed generation capacity located in, or capable of delivering electricity to, a power region.

(b) No change

(c) In determining the percentage shares of installed generation capacity under this section, the commission shall combine capacity owned and <u>or</u> controlled by a power generation company and any entity that is affiliated with that power generation company within the power region, reduced by the installed generation capacity of those facilities that are made subject to capacity auctions under Sections 39.153(a) and (d).

(d) No change

(e) In determining the percentage shares of installed generation capacity owned and or controlled by a power generation company under this section and Section 39.156, the commission shall, for purposes of calculating the numerator, reduce the installed generation capacity owned and or controlled by that power generation company by the installed generation capacity of any "grandfathered facility" within an ozone nonattainment area as of September 1, 1999, for which that power generation company has commenced complying or made a binding commitment to comply with Section 39.264. This subsection applies only to a power generation company that is affiliated with an electric utility that owned and controlled more than 27 percent of the installed generation capacity in the power region on January 1, 1999.

#### Sec. 39.155. COMMISSION ASSESSMENT OF MARKET POWER.

(a) Each person, municipally owned utility, electric cooperative, and river authority that owns <u>or</u> <u>controls</u> generation facilities and offers electricity for sale in this state shall report to the commission its installed generation capacity, the total amount of capacity available for sale to others, the total amount of capacity dedicated to its own use, its annual wholesale power sales in the state, its annual retail power sales in the state, and any other information necessary for the commission to assess market power or the development of a competitive retail market in the state. The commission shall by rule prescribe the nature and detail of the reporting requirements and shall administer

those reporting requirements in a manner that ensures the confidentiality of competitively sensitive information.

(b)-(d) No change

#### Sec. 39.156. MARKET POWER MITIGATION PLAN.

(a) In this section, "market power mitigation plan" or "plan" means a written proposal by an electric utility or a power generation company for reducing its ownership and <u>or</u> control of installed generation capacity as required by Section 39.154.

(b) An electric utility or power generation company owning and <u>or</u> controlling, or any combination <u>thereof</u>, more than 20 percent of the generation capacity located in, or capable of delivering electricity to, a power region shall file a market power mitigation plan with the commission not later than December 1, 2000.

(c)-(j) No change

#### Sec. 39.157. COMMISSION AUTHORITY TO ADDRESS MARKET POWER.

(a) No change

(b) Beginning on the date of introduction of customer choice in a power region, a person that owns <u>or</u> <u>controls</u> generation facilities may not own transmission or distribution facilities in this state except for those facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility" under Section 31.002. However, nothing in this chapter shall prohibit a power generation company affiliated with a transmission and distribution utility from owning <u>or controlling</u> generation facilities.

(c)-(i) No change

#### Sec. 39.158. MERGERS AND CONSOLIDATIONS.

(a) An person who owners or controls of electric generation facilities that offers electricity for sale in the state and proposes to merge, consolidate, or otherwise become affiliated with another person who ownser of or controls electric generation facilities that offers electricity for sale in this state shall obtain the approval of the commission before closing if the electricity offered for sale in the power region by the merged, consolidated, or affiliated entity will exceed one percent of the total electricity for sale in the power region. The approval shall be requested at least 120 days before the date of the proposed closing. The commission shall approve the transaction unless the commission finds that the transaction results in a violation of Section 39.154. If the commission finds that the transaction on adoption of reasonable modifications to the transaction as prescribed by the commission to mitigate potential market power abuses.

(b)-(d) No change

#### Sec. 39.407. CUSTOMER CHOICE AND RELEVANT MARKET AND RELATED MATTERS.

(a) If an electric utility chooses on or after January 1, 2007, to participate in customer choice, the commission may not authorize customer choice until the applicable power region has been certified as a qualifying power region under Section 39.152(a). Except as otherwise provided by this subsection, the commission shall certify that the requirements of Section 39.152(a)(3) are met for electric utilities subject to this subchapter only upon a finding that the total capacity owned and or controlled, or any combination thereof, by each such electric utility and its affiliates does not exceed 20 percent of the total installed generation capacity within the constrained geographic region served by each such electric utility plus the total available transmission capacity capable of delivering firm power and energy to that constrained

geographic region. Not later than May 1, 2002, each electric utility subject to this subchapter shall submit to the electric utility restructuring legislative oversight committee an analysis of the needed transmission facilities necessary to make the electric utility's service area transmission capability comparable to areas within the ERCOT power region. On or after September 1, 2003, each electric utility subject to this subchapter shall file the utility's plans to develop the utility's transmission interconnections with the utility's power region or other adjacent power regions. The commission shall review the plan and not later than the 180th day after the date the plan is filed, determine the additional transmission facilities necessary to provide access to power and energy that is comparable to the access provided in areas within the ERCOT power region; provided, however, that if a hearing is requested by any party to the proceeding, the 180-day deadline will be extended one day for each day of hearings. The commission shall, as a part of the commission's approval of the plan, approve a rate rider mechanism for the recovery of the incremental costs of those facilities after the facilities are completed and in-service. A finding of need under this subsection shall meet the requirements of Sections 37.056(c)(1), (2), and (4)(E). The commission may certify that the requirements of Section 39.152(a)(3) are met for electric utilities subject to this subchapter if the commission finds that:

(1) each such utility has sufficient transmission facilities to provide customers access to power and energy from capacity controlled by suppliers not affiliated with the incumbent utility that is comparable to the access to power and energy from capacity controlled by suppliers not affiliated with the incumbent utilities in areas of the ERCOT power region; and

(2) the total capacity owned and or controlled, or any combination thereof, by each such electric utility and its affiliates does not exceed 20 percent of the total installed generation capacity within the power region.

(b)-(c) No change

#### Sec. 39.453. CUSTOMER CHOICE AND RELEVANT MARKET AND RELATED MATTERS.

(a) No change

(b) The commission shall certify that the requirement of Section 39.152(a)(3) is met for an electric utility subject to this subchapter only if the commission finds that the total capacity owned and <u>or</u> controlled, or any combination thereof, by the electric utility and the utility's affiliates does not exceed 20 percent of the total installed generation capacity within the power region of that utility.

### b. Commission Authority to Address Market Power

PURA §39.157(a) vests the Commission with authority to monitor market power associated with the generation, transmission, distribution, and sale of electricity in Texas. PURA §39.157(a) further provides that on a finding that market power abuses are occurring, the Commission shall require reasonable mitigation of the market power abuse. Although PURA §39.157(a) lists a number of remedies for market power abuse, the list does not include refunds or disgorgement of revenues obtained through the abuse of market power.

The abuse of market power can potentially dramatically increase the costs to other market participants and customers. The Legislature should provide clear authority to permit the Commission to, in addition to ordering the other mitigation and remedies currently in the statute, require market participants who abuse market power to disgorge the improper revenues received in order to adequately protect other market participants and customers.

#### Sec. 39.157. COMMISSION AUTHORITY TO ADDRESS MARKET POWER.

The commission shall monitor market power associated with the generation, transmission, (a) distribution, and sale of electricity in this state. On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or civil penalties as necessary to eliminate or to remedy the market power abuse or violation as authorized by Chapter 15, requiring refunds or disgorgement of revenues received as a result of market power abuses, by imposing an administrative penalty as authorized by Chapter 15, or by suspending, revoking, or amending a certificate or registration as authorized by Section 39.356. Section 15.024(c) does not apply to an administrative penalty imposed under this section. For purposes of this subchapter, market power abuses are practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion. A violation of the code of conduct provided by Subsection (d) that materially impairs the ability of a person to compete in a competitive market shall be deemed to be an abuse of market power. The possession of a high market share in a market open to competition may not, of itself, be deemed to be an abuse of market power; however, this sentence shall not affect the application of state and federal antitrust laws.

(b)-(i) No change

#### c. Securitization of Non-Stranded-Cost True-Up Balances

Current provisions in PURA §§39.262 and 39.301 allow for the securitization of stranded costs and regulatory assets, but do not provide for the securitization of other true-up balances determined under §39.262. During the 2005 Legislative Session, CenterPoint proposed legislation that would have authorized securitization of positive amounts of non-stranded-cost true-up balances, but the legislation did not pass. Staff expects that during the 2007 Session, CenterPoint will make efforts to pass similar legislation. If proposed, such legislation would require minimal amendments to existing statutory language.

Because of the existing statutory provisions that limit securitization of true-up balances to stranded costs only, CenterPoint is currently recovering approximately \$600 million of non-stranded-cost true-up balances through a CTC. If this amount were securitized at the more favorable interest rates afforded by securitization financing, current market conditions suggest that ratepayer savings in the range of \$15 million per year could be achieved.

#### Sec. 39.262. TRUE-UP PROCEEDING.

(a)-(b) No change

(c) After January 10, 2004, at a schedule and under procedures to be determined by the commission, each transmission and distribution utility, its affiliated retail electric provider, and its affiliated power generation company shall jointly file to finalize stranded costs under Subsections (h) and (i) and reconcile those costs with the estimated stranded costs used to develop the competition transition charge in the proceeding held under Section 39.201. Any resulting difference shall be applied to the nonbypassable

delivery rates of the transmission and distribution utility, except that at the utility's option, any or all of the **amounts recovered under this section** remaining stranded costs may be securitized under Subchapter G.

(d)-(k) No change

#### Sec. 39.301. PURPOSE.

The purpose of this subchapter is to enable utilities to use securitization financing to recover regulatory assets and <u>all other amounts determined under Section 39.262 and any amounts being recovered</u> <u>under a competition transition charge determined as a result of the proceedings under Sections</u> <u>39.201 and 39.262. This stranded costs, because this type of debt will lower the carrying costs of the assets relative to the costs that would be incurred using conventional utility financing methods. The proceeds of the transition bonds shall be used solely for the purposes of reducing the amount of recoverable regulatory assets and <u>other amounts stranded costs</u>, as determined by the commission in accordance with this chapter, through the refinancing or retirement of utility debt or equity. The commission shall ensure that securitization provides tangible and quantifiable benefits to ratepayers, greater than would have been achieved absent the issuance of transition bonds. The commission shall ensure that the structuring and pricing of the transition bonds result in the lowest transition bond charges consistent with market conditions and the terms of the financing order. The amount securitized may not exceed the present value of the revenue requirement over the life of the proposed transition bond associated with the regulatory assets or stranded costs sought to be securitized. The present value calculation shall use a discount rate equal to the proposed interest rate on the transition bonds.</u>

#### Sec. 39.302. DEFINITIONS.

In this subchapter:

(1)-(3) No change

(4) "Qualified costs" means 100 percent of an electric utility's regulatory assets and 75 percent of its recoverable costs determined by the commission under Section 39.201 and any remaining **amounts** stranded costs determined under Section 39.262 together with the costs of issuing, supporting, and servicing transition bonds and any costs of retiring and refunding the electric utility's existing debt and equity securities in connection with the issuance of transition bonds. The term includes the costs to the commission of acquiring professional services for the purpose of evaluating proposed transactions under Section 39.201 and this subchapter.

(5)-(8) No change

#### Sec. 39.303. FINANCING ORDERS; TERMS.

(a) The commission shall adopt a financing order, on application of a utility to recover the utility's regulatory assets and <u>other amounts determined</u> eligible stranded costs under Section 39.201 or 39.262, on making a finding that the total amount of revenues to be collected under the financing order is less than the revenue requirement that would be recovered over the remaining life of the stranded costs using conventional financing methods and that the financing order is consistent with the standards in Section 39.301.

(b) The financing order shall detail the amount of regulatory assets and <u>other amounts stranded costs</u> to be recovered and the period over which the nonbypassable transition charges shall be recovered, which period may not exceed 15 years. <u>If any amounts determined pursuant to Section 39.262 are subject to judicial review at the time of the securitization proceeding, the financing order shall include an adjustment mechanism requiring the utility to adjust its rates, other than transition charges, or provide credits, other than credits to transition charges, in a manner that would refund over the remaining life of the transition bonds any overpayments resulting from securitization of amounts in excess of the amount resulting from a final determination after completion of all appellate reviews.</u>

<u>The adjustment mechanism shall not affect the stream of revenues available to service the transition</u> <u>bonds. No adjustment shall be made under this subsection until all appellate reviews, including, if</u> <u>applicable, appellate reviews following a commission decision on remand of its original orders, have</u> <u>been completed.</u>

(c)-(g) No change

## d. Energy Efficiency Goal

Programs to influence how customers use electricity have several different objectives. They may be intended to reduce the level of demand for electricity when the demand is at its peak, in order to reduce the costs that business enterprises incur to provide electric service. The programs may be intended to improve the efficiency of customers' use of electricity, either to reduce costs to customers or to reduce the air emissions that result from burning fuels to produce electricity. Events in the recent past may result in changing perspectives on how important these objectives are, relative to each other, and relative to other electric issues.

As the demand for electricity in Texas grows, reducing the rate of growth in demand remains an important objective, particularly in major cities, where it is difficult to build new generation and transmission facilities. The major cities in Texas continue to face challenges in meeting national air-quality standards for ground-level ozone, and the public concern about global-warming gases from power plants has increased since the retail competition law was enacted in 1999. High energy prices and these environmental concerns suggest there is a need to enhance energy efficiency programs, particularly for customers who face obstacles to investing in appliances or housing improvements that would reduce their consumption of electricity. Existing law includes a numerical goal for demand savings, but does not include a goal for energy savings. The Commission recommends that the energy efficiency provisions of PURA be amended to authorize the Commission to adopt an explicit, numerical goal for energy savings.

#### Sec. 39.905. GOAL FOR ENERGY EFFICIENCY.

(a) It is the goal of the legislature that:

(1) electric utilities will administer energy savings incentive programs in a market-neutral, nondiscriminatory manner but will not offer underlying competitive services;

(2) all customers, in all customer classes, have a choice of and access to energy efficiency alternatives and other choices from the market that allow each customer to reduce energy consumption, peak demand, or energy costs; and

(3) each electric utility will provide, through market-based standard offer programs or limited, targeted, market-transformation programs, incentives sufficient for retail electric providers and competitive energy service providers to acquire additional cost-effective energy efficiency equivalent to at least 10 percent of the electric utility's annual growth in demand <u>and energy savings consistent with goals established by the commission</u>.

(b)-(f) No change

## e. Decommissioning Funding for New Nuclear Generation

The rules of the Nuclear Regulatory Commission (NRC) require that the operators of nuclear facilities provide guarantees that they will have the financial capability of decommissioning and decontaminating the facilities when they cease operations. It is necessary to provide such guarantees, because of the cost of decommissioning and the risk to the public health of nuclear contamination. The nuclear generating units operating in the United States typically use nuclear decommissioning trust funds to meet the NRC requirement by reserving funds to pay for the safe dismantling, decontamination, and disposal of a nuclear generating unit upon completion of its service life. Recent decommissioning cost estimates are \$1.094 billion for both units at the South Texas Project, and \$1.08 billion for the Comanche Peak units. Decommissioning costs for a new nuclear power plant with two units would likely be similar.

Current legislation addresses decommissioning funding for existing nuclear units, but does not address funding for new nuclear units. Historically, electric utility rates were regulated, and the Commission established rates to allow the owners an opportunity to recover the capital costs and operating expenses incurred in the course of providing service. The estimated costs for dismantling and decommissioning nuclear generation facilities at the completion of their service life were included as a part of the regulated rates. Owners of an existing nuclear unit are required to fund, over the unit's operating life, a trust that will provide for costs incurred during the unit's decommissioning.<sup>89</sup> The utilities that owned nuclear plants established and began funding such trusts before the introduction of retail competition. PURA §39.205 provides that after the introduction of retail competition, any remaining costs associated with nuclear decommissioning obligations will continue to be subject to cost-of-service rate regulation and included as a non-bypassable charge to retail customers. However, PURA §39.205 applies only to existing units; they are not applicable to new units.<sup>90</sup> If new nuclear units are constructed, the developers will need to comply with NRC regulations relating to decommissioning funding.

To receive a license to operate a nuclear unit, the unit owner must meet a number of technical and financial requirements established by the NRC, including having sufficient funds available to fund decommissioning when the license for the unit expires.<sup>91</sup> The main objective of the NRC's decommissioning requirement is to ensure that

<sup>&</sup>lt;sup>89</sup> PUC SUBST. R. 25.231(b)(1)(F)(i) and 25.301(a)(2) require that all decommissioning funds be placed in an external, irrevocable decommissioning trust.

<sup>&</sup>lt;sup>90</sup> Similarly, the Commission's rules apply to utilities and Transferee Companies that have purchased an ownership interest in the existing nuclear plants, but would not apply to a power generation company that would develop a nuclear generation unit in the competitive environment.

<sup>&</sup>lt;sup>91</sup> <u>http://www.nrc.gov/reading-rm/doc-collections/cfr/part050/full-text.html#part050-0075</u>

decommissioning is completed in a way that protects the health and safety of the public once operations cease.<sup>92</sup>

The NRC guidelines specify that a nuclear unit licensee may use the following methods to provide financial assurance for decommissioning:

- prepayment;
- an external sinking fund in which deposits are made at least annually; or
- a surety method or insurance.

Prepayment is a deposit of cash or liquid assets made before the start of operation into an account segregated from the licensee's assets and outside the licensee's administrative control, such that the amount of funds would be sufficient to pay the decommissioning costs. Prepayment may be in the form of a trust, escrow account, government fund, certificate of deposit, deposit of government securities, or other payment acceptable to the NRC. Actual earnings on existing funds are used to calculate future fund needs.

An external sinking fund is a fund for which the licensee sets funds aside periodically in an account segregated from the licensee's assets and outside the licensee's administrative control, and for which the total amount of funds would be sufficient to pay decommissioning costs at the time termination of operation is expected. An external sinking fund may be in the form of a trust, escrow account, government fund, certificate of deposit, deposit of government securities, or other payment acceptable to the NRC.

Surety, insurance, and other guarantee methods provide that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. Any surety method or insurance used to provide financial assurance for decommissioning must meet several conditions such as the required length, payment terms, and amounts provided by an agreement, and be subject to NRC review and approval. Contractual obligations on the part of a licensee's customer(s) to provide funds for decommissioning are also acceptable as long as NRC requirements are met.

The external sinking fund is the most commonly used method. It is generally recognized that an external sinking fund is an equitable and economically viable method for funding decommissioning costs, because it permits funding over the life of the unit.<sup>93</sup> Prepayment would be expensive due to the large payment prior to operation. Insurance or some other method of surety to guarantee the payment of decommissioning costs would be similarly expensive, if coverage could be obtained at all.

<sup>&</sup>lt;sup>92</sup> The NRC issued general requirements on decommissioning for operating license applicants and existing licensees in June 1988. It also issued Regulatory Guide 1.159, *Assuring the Availability of Funds for Decommissioning Nuclear Reactors*, in August 1990.

<sup>&</sup>lt;sup>93</sup> SECY: Final Rule on Financial Assurance Requirements for Decommissioning Nuclear Power Reactors, SECY-98-164 (Jul. 2, 1998). <u>http://www.nrc.gov/reading-rm/doc-</u> collections/commission/secys/1998/secy1998-164/1998-164scy.html# 1 57

Meeting NRC decommissioning funding requirements may be challenging for a PGC in a competitive market because the external sinking fund option is probably not available. The NRC permits the sinking fund method to be used in connection with entities that are subject to cost-of-service regulation or a non-bypassable charge, but a competitive PGC in the Texas market would not be subject to such regulation.

Rate regulation provides assurances to the owner of a generating unit that it can recover its reasonable and necessary costs, including decommissioning costs, during the generating unit's useful life. In a competitive market, however, a unit owner is subject to competition from other forms of generation, so that a nuclear unit could become uncompetitive, leading to the insolvency of its owners. If decommissioning costs were not fully funded, it is unclear how the decommissioning would be completed. The prepayment and insurance options are likely to be so expensive that they might deter a PGC from developing a nuclear plant in Texas.

Reducing the up-front funding requirements for decommissioning new nuclear units in the competitive Texas market would facilitate the construction of new nuclear units. On the other hand, measures to reduce the up-front funding requirements should be designed to minimize subsidies from competitors or customers. The Commission suggests that if legislation is enacted to facilitate an external decommissioning trust fund for new nuclear units, the legislation should minimize the risk to competitors and customers. The following are funding alternatives that are consistent with NRC requirements:

- Electric customers in competitive areas could fund an external trust through a fee like the SBF fee.
- Electric customers in competitive areas could provide initial funding for an external trust fund and the nuclear plant owner would then periodically repay amounts initially provided by customers. Under this arrangement, the customers would, in effect, be guarantors of the owner's obligation.

Under either of these alternatives, the Commission should have the authority to regulate any decommissioning fees and establish financial criteria for companies that seek to use these funding alternatives.

# f. System Benefit Fund Fee

PURA §39.903 permits the money in the SBF to be appropriated for the purposes provided by the section "or other law," requires the Commission to set the revenue requirements and nonbypassable fees (system benefit fee) on a yearly basis, and sets forth the purposes for which the SBF is to be used. The language "or other law" and the variations in appropriations made in previous legislative sessions for the purposes set forth in the section have created confusion as to how the nonbypassable fee should be set in years in which appropriations are not made for one or all of the purposes set forth by the section. It is recommended that the statute be amended to require the Commission to set the level of the fee to recover only costs for which funds have been appropriated.

Such an amendment would remove any ambiguity regarding the purposes of the fund and the Commission's duty and authority to set the nonbypassable fees.

#### Sec. 39.903. SYSTEM BENEFIT FUND. (As amended by HB 3318)

(a) The system benefit fund is an account in the general revenue fund. Money in the account may be appropriated only for the purposes provided by this section or other law. Interest earned on the system benefit fund shall be credited to the fund. Section 403.095, Government Code, does not apply to the system benefit fund.

(b)-(c) No change

(d) The commission shall annually review and approve system benefit fund accounts, projected revenue requirements, and proposed nonbypassable fees. The commission shall set the proposed nonbypassable fees at an amount that is sufficient to ensure that funding and cash flow are available for the purposes for which funds have been appropriated. The commission shall report to the electric utility restructuring legislative oversight committee if the system benefit fund fee is insufficient to fund the purposes set forth in Subsection (e) to the extent required by this section

(e)-(l) No change

## g. Electric System Security

Current provisions of law give the Commission authority with respect to establishing reliability standards, but they do not directly address the grid security issues related to terrorism or other possible attacks on the system. It would be appropriate to amend PURA to address the security of the electric system by authorizing the Commission to:

- prescribe and enforce grid security and emergency management rules with respect to all market participants; and
- suspend market rules in an energy emergency declared by the Governor.

Current law directs the Commission to implement service quality and reliability standards for the delivery of energy by investor-owned utilities, and requires municipal utilities, cooperatives, REPs, power marketers, and PGCs to follow the reliability rules established by an independent organization. The Commission also has oversight authority over an independent organization. The existing statutory authority should be modified to give the Commission explicit and direct authority to prescribe and enforce grid security and emergency management rules with respect to all market participants.

There is nothing in current law that expressly allows the suspension of market rules in an emergency. Such authority could prevent significant economic harm to customers and market participants in an emergency situation. The existing statutory authority should be modified to give the Commission explicit authority to suspend market rules after a catastrophic event, as declared by the Governor, that disrupts electricity markets. Legislation should also authorize the Commission to adopt streamlined procedures to carry out this responsibility. Because of the likelihood that the Commission would have to act quickly to assess the extent of an emergency and suspend market rules, the

Commission should have the authority to make such a decision outside of the context of a contested case or rulemaking proceeding.

#### Sec. 38.001. GENERAL STANDARD.

An electric utility, **municipally owned utility**, **power generation company**, **independent organization**, and an electric cooperative shall furnish service, instrumentalities, and facilities that are safe, adequate, efficient, and reasonable.

# Sec. 38.005. ELECTRIC SERVICE RELIABILITY, MEASURES SECURITY, AND EMERGENCY RESPONSE.

(a) The commission shall <u>adopt and enforce rules as necessary or appropriate to ensure service</u> <u>quality and reliability implement service quality and reliability standards</u> relating to the delivery of electricity to retail customers by electric utilities and transmission 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)-(f) No change

(g) A retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, independent organization, or power generation company and any person scheduling power or operating electrical facilities on their behalf shall observe all reliability, security, and emergency management rules and orders established by the commission. The commission may take the following actions for failure to comply with this subsection: suspend, revoke, or amend a retail electric provider's certificate; suspend or revoke a power marketer's or power generation company's registration; and, for any entity subject to this subsection, obtain enforcement and penalties pursuant to Chapter 15, Subchapter B. This section does not authorize the commission to establish or enforce quality standards for local distribution service provided by a municipally owned utility or an electric cooperative or require reporting of local distribution service quality by a municipally owned utility or an electric cooperative.

# Sec. 39.103. COMMISSION AUTHORITY TO DELAY OR SUSPEND COMPETITION AND SET NEW RATES.

(a) If the commission determines under Section 39.104 that a power region is unable to offer fair competition and reliable service to all retail customer classes on January 1, 2002, the commission shall delay customer choice for the power region and may on or after January 1, 2002, establish new rates for all electric utilities in the power region as provided by Chapter 36.

(b) In the event of a catastrophic event that results in an energy emergency that disrupts electricity markets, as declared by the Governor, the commission may suspend competitive wholesale and retail market rules and set rates. The commission shall adopt rules that provide for a streamlined procedure to exercise its authority under this subsection, including provisions for providing notice to affected entities, but is not required to conduct a contested case to exercise its authority. If the commission determines in a contested case that an entity violated a commission order issued pursuant to this subsection, the commission may order the entity to refund any

#### <u>compensation obtained as a result of the violation and may impose administrative penalties and</u> <u>suspend, revoke, or amend the entity's commission-issued license pursuant to Subsection 38.005(g).</u>

Additionally, current law (Chapter 551 of the Government Code) does not provide an exception to the requirement that the Commission meet in open meeting to discuss the security of the electrical network that provides service to customers in the state. While not all deliberations by the Commission related to grid security would necessarily need to be discussed in closed meeting, certain deliberations relating to plans to protect the electric network; plans to prevent, disrupt, or minimize the impact of an attack on the electric network; investigation of threats to the electric network; assessments of the vulnerability of the electric network; and plans for restoring service if electric facilities are damaged, should be considered in closed meeting. Therefore, the Commission requests that the Legislature adopt an exception to the Open Meetings Act that would allow the Commission to meet in closed meeting to deliberate matters relating to the security of the electrical network if needed.

The Legislature should also consider providing an exception to the Public Information Act (Chapter 552 of the Government Code) that would allow the Commission to except from public disclosure documents that relate to plans to protect the electric network, plans to prevent, disrupt, or minimize the impact of an attack on the electric network, investigation of threats to the electric network, assessments of the vulnerability of the electric network, and plans for restoring service if electric facilities are damaged.

## h. Authority of the Commission with Respect to Qualified Scheduling Entities, Municipally Owned Utilities, and Electric Cooperatives

PURA §39.151(j) requires REPs, municipally owned utilities, electric cooperatives, power marketers, TDUs, and PGCs to observe all policies, rules, guidelines, and procedures established by ERCOT, and provides for revocation, suspension, or amendments of certain certificates or registrations or the imposition of administrative penalties for violations of that requirement.

Even though the Commission does not certificate or register municipally owned utilities or electric cooperatives, it believes that it necessarily has authority to assess administrative penalties on these entities for a failure to comply with ERCOT rules. However, while Chapter 15 of PURA permits the Commission to impose administrative penalties on "persons" who violate PURA, the definition of "person" in PURA §11.003(14) does not include a municipally owned utility or an electric cooperative, which could potentially lead these entities to argue that the Commission cannot assess administrative penalties for violations of ERCOT rules. Clarification of PURA to make it clear that the Commission can assess penalties on all market participants, including municipally owned utilities and electric cooperatives, would remove this potential ambiguity. The Commission also believes that it necessarily has implied authority to order refunds or disgorgement of improper revenues obtained through a failure to follow ERCOT rules. However, it would be preferable to eliminate any ambiguity by stating this authority explicitly in PURA §39.151.

Additionally, the ERCOT primary rules (ERCOT Protocols), as initially approved by the Commission, established QSEs as the primary entity that interfaces with ERCOT with respect to the scheduling of power and participating in ERCOT-operated markets. The Commission believes that, because it has authority over the ERCOT Protocols, it necessarily has authority over QSEs. Clarification of this would prevent claims that the Commission does not have such authority.

Lastly, although PURA §39.151(j) requires municipally owned utilities and electric cooperatives to comply with ERCOT rules, PURA §39.002, which outlines the applicability of Chapter 39, does not include PURA §39.151(j) in the list of provisions that are applicable to municipally owned utilities and electric cooperatives. Additionally, PURA §39.002 does not include PURA §39.157(a), which provides the Commission with authority to remedy market power abuses. Corresponding references are also not included in PURA §\$40.001 and 41.001. The Commission believes that all market participants, including municipally owned utilities and electric cooperatives, should be prohibited from abusing market power, and that the Commission should have appropriate tools available to enforce that prohibition.

#### Sec. 15.020. DEFINITIONS.

# In this subchapter, the term "person" includes a municipally owned utility and an electric cooperative with respect to violations of Sections 39.151(j) and 39.157(a).

#### Sec. 39.002. APPLICABILITY.

This chapter, other than Sections <u>39.151(j)</u>, 39.155, <u>39.157(a)</u>, 39.157(e), 39.203, 39.903, and 39.904, does not apply to a municipally owned utility or an electric cooperative. Sections 39.157(e), 39.203, and 39.904, however, apply only to a municipally owned utility or an electric cooperative that is offering customer choice. If there is a conflict between the specific provisions of this chapter and any other provisions of this title, except for Chapters 40 and 41, the provisions of this chapter control.

#### Sec. 39.151. ESSENTIAL ORGANIZATIONS.

(a)-(i) No change

(j) A retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, or power generation company, or any other entity scheduling power on their behalf or any entity who participates in markets operated by the independent system operator in ERCOT, shall observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT. Failure to comply with this subsection may result in the revocation, suspension, or amendment of a certificate as provided by Section 39.356 or in the imposition of an administrative penalty as provided by Section 39.357 on any entity subject to this subsection. The commission may also require refunds or disgorgement of revenues that result from a failure to comply with this subsection.

(k)-(m) No change

#### Sec. 40.001. APPLICABLE LAW.

(a) Notwithstanding any other provision of law, except Sections <u>15.020</u>, <u>39.151(j)</u>, <u>39.155</u>, <u>39.157(a)</u>, <u>39.157(e)</u>, <u>39.203</u>, <u>39.903</u>, and <u>39.904</u>, this chapter governs the transition to and the establishment of a fully competitive electric power industry for municipally owned utilities. With respect to the regulation of municipally owned utilities, this chapter controls over any other provision of this title, except for sections in which the term "municipally owned utility" is specifically used.

(b)-(d) No change

#### Sec. 41.001. APPLICABLE LAW.

Notwithstanding any other provision of law, except Sections <u>15.020</u>, <u>39.151(j)</u>, <u>39.155</u>, <u>39.157(a)</u>, <u>39.157(e)</u>, <u>39.203</u>, <u>39.903</u>, and <u>39.904</u>, this chapter governs the transition to and the establishment of a fully competitive electric power industry for electric cooperatives. Regarding the regulation of electric cooperatives, this chapter shall control over any other provision of this title, except for sections in which the term "electric cooperative" is specifically used.

## i. Repeal of Goal for Natural Gas

The price of electricity in the wholesale market within ERCOT closely correlates to natural gas prices, and as natural gas prices increased from 2002 through 2005, wholesale and retail electricity prices also increased. Natural gas has gone from being an abundant fuel that the Legislature promoted as a fuel for electric generation to a scarce, high-priced fuel, and its promotion as a generation fuel is probably no longer appropriate.

Hurricanes Katrina and Rita caused significant damage to gas-production facilities in the Gulf of Mexico and to onshore processing and pipeline infrastructure, resulting in dramatic increases in natural gas prices. These hurricanes also revealed that the natural gas industry is vulnerable to supply interruptions from strong storms in the Gulf of Mexico. Current high prices for natural gas are stimulating exploration in many areas of the country, including Texas, and are stimulating investment in terminals that will permit the import of liquefied natural gas (LNG) into the United States. Despite these efforts, natural gas is not the highly desirable fuel for electric generation that it was in 1999, when the retail competition legislation was enacted. Companies that are developing new generation projects in Texas are more interested in wind power and coal than in natural gas, because of the price and availability of these energy sources. According to ERCOT, of the planned generation projects that are under development, 30% would be coal-fired, 23% would be natural gas-fired, 7% would be nuclear, and 37% would be wind-powered.

The Commission believes that it is appropriate for the Legislature to facilitate the diversification of the generation fuels that will be used to meet Texas' future energy needs by repealing the provisions of PURA that promoted natural gas as an electric generation fuel. To accomplish this, PURA §§39.9044 and 39.9048 should be repealed. These sections are set out below.
#### Sec. 39.9044. GOAL FOR NATURAL GAS.

(a) It is the intent of the legislature that 50 percent of the megawatts of generating capacity installed in this state after January 1, 2000, use natural gas. To the extent permitted by law, the commission shall establish a program to encourage utilities to comply with this section by using natural gas produced in this state as the preferential fuel. This section does not apply to generating capacity for renewable energy technologies.

(b) The commission shall establish a natural gas energy credits trading program. Any power generation company, municipally owned utility, or electric cooperative that does not satisfy the requirements of Subsection (a) by directly owning or purchasing capacity using natural gas technologies shall purchase sufficient natural gas energy credits to satisfy the requirements by holding natural gas energy credits in lieu of capacity from natural gas energy technologies.

(c) Not later than January 1, 2000, the commission shall adopt rules necessary to administer and enforce this section and to perform any necessary studies in cooperation with the Railroad Commission of Texas. At a minimum, the rules shall:

(1) establish the minimum annual natural gas generation requirement for each power generation company, municipally owned utility, and electric cooperative operating in this state in a manner reasonably calculated by the commission to produce, on a statewide basis, compliance with the requirement prescribed by Subsection (a); and

(2) specify reasonable performance standards that all natural gas capacity additions must meet to count against the requirement prescribed by Subsection (a) and that:

(A) are designed and operated so as to maximize the energy output from the capacity additions in accordance with then-current industry standards and best industry standards; and

(B) encourage the development, construction, and operation of new natural gas energy projects at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial natural gas resources.

(d) The commission, with the assistance of the Railroad Commission of Texas, shall adopt rules allowing and encouraging retail electric providers and municipally owned utilities and electric cooperatives that have adopted customer choice to market electricity generated using natural gas produced in this state as environmentally beneficial. The rules shall allow a provider, municipally owned utility, or cooperative to:

(1) emphasize that natural gas produced in this state is the cleanest-burning fossil fuel; and

(2) label the electricity generated using natural gas produced in this state as "green" electricity.

(e) In this section, "natural gas technology" means any technology that exclusively relies on natural gas as a primary fuel source.

#### Sec. 39.9048. NATURAL GAS FUEL.

It is the intent of the legislature that:

(1) the cost of generating electricity remain as low as possible; and

(2) the state establish and publicize a program to keep the costs of fuel, such as natural gas, used for generating electricity low.

## **3.** Potential Actions if Electric Competition is Not Producing Adequate Benefits for Residential Electric Customers

Despite the fact that residential customers have been able to achieve significant savings by switching to a rate plan other than the price to beat, many residential customers have not done so. As a result, these customers have paid a rate that is higher than most of the competitive rates being offered by competitive REPs. With the end of the price to beat on January 1, 2007, some customers are paying rates that are significantly higher than rates available in the market. If their past behavior is useful in predicting their future behavior, many of them can be expected to continue paying rates that are higher than rates available in the market.

If the Legislature determines that retail competition is not producing adequate benefits to the residential customer class, the Commission recommends that the Legislature consider the following options, which could provide additional benefits to residential customers.

## a. Mandate the Disclosure of the Names of Residential Customers Served by the AREP Under the PTB at the End of the PTB Period

## Sec. 39.101. CUSTOMER SAFEGUARDS.

(a) Before customer choice begins on January 1, 2002, the commission shall ensure that retail customer protections are established that entitle a customer:

(1) to safe, reliable, and reasonably priced electricity, including protection against service disconnections in an extreme weather emergency as provided by Subsection (h) or in cases of medical emergency or nonpayment for unrelated services;

(2) to privacy of customer consumption and credit information, but the release of information identifying residential customers that were served by the affiliated retail electric provider at the end of the price to beat period to competitive retail electric providers shall not be deemed as a violation of customer privacy;

(3) to bills presented in a clear format and in language readily understandable by customers;

(4) to the option to have all electric services on a single bill, except in those instances where multiple bills are allowed under Chapters 40 and 41;

(5) to protection from discrimination on the basis of race, color, sex, nationality, religion, or marital status;

(6) to accuracy of metering and billing;

(7) to information in English and Spanish and any other language as necessary concerning rates, key terms and conditions, in a standard format that will permit comparisons between price and service offerings, and the environmental impact of certain production facilities;

(8) to information in English and Spanish and any other language as necessary concerning low-income assistance programs and deferred payment plans; and

- (9) to other information or protections necessary to ensure high-quality service to customers.
- (b)-(h) No change

#### Sec. 39.202. PRICE TO BEAT.

(a)-(p) No change

(q) After the expiration of the price to beat period, on a schedule to be determined by the commission, the affiliated retail electric providers shall release information to the competitive retail electric providers that identifies the residential customers receiving retail electric service from the affiliated retail electric providers.

# b. Require Residential Customers to Select a REP After the End of the PTB

The Commission could require the selection of a REP by residential customers who were receiving price to beat service from an affiliated REP at the end of 2006. The Commission envisions using a balloting process for selecting a competitive REP, but the language recommended below gives the Commission some flexibility in conducting such a program, if the Legislature concludes that such a program is appropriate.

#### Sec. 39.101. CUSTOMER SAFEGUARDS.

- (a) No change
- (b) A customer is entitled:
  - (1) to be informed about rights and opportunities in the transition to a competitive electric industry;

(2) to choose the customer's retail electric provider consistent with this chapter, to have that choice honored, and to assume that the customer's chosen provider will not be changed without the customer's informed consent. Nothing in this provision shall prevent a residential customer receiving service from an affiliated retail electric provider under a month-to-month service plan from being transferred to a competitive retail electric provider after the end of the price to beat period in any commission authorized reallocation plan;

(3) to have access to providers of energy efficiency services, to on-site distributed generation, and to providers of energy generated by renewable energy resources;

(4) to be served by a provider of last resort that offers a commission-approved standard service package;

(5) to receive sufficient information to make an informed choice of service provider;

(6) to be protected from unfair, misleading, or deceptive practices, including protection from being billed for services that were not authorized or provided; and

(7) to have an impartial and prompt resolution of disputes with its chosen retail electric provider and transmission and distribution utility.

(c)-(h) No change

#### Sec. 39.102. RETAIL CUSTOMER CHOICE.

(a) No change

(b) The affiliated retail electric provider of the electric utility serving a retail customer on December 31, 2001, may continue to serve that customer until the customer chooses service from a different retail electric provider, an electric cooperative offering customer choice, or the customer is transitioned to another retail electric provider, in accordance with Section 39.202(q).

(c)-(e) No change

## Sec. 39.202. PRICE TO BEAT.

(a)-(p) No change

(q) After the expiration of the price to beat period, the commission may conduct a program to require residential customers receiving service from an affiliated retail electric provider under a month-to-month service plan to select a retail electric provider. Customers who do not affirmatively select a retail electric provider may be switched to a competitive retail electric provider, or switched to a different product with their existing provider.

## c. Increase Customer Education Funding

The Commission's appropriation for customer education from the System Benefit Fund should be increased to an appropriate level for fiscal years 2008 and 2009. Annual appropriations for customer education have ranged from \$12 million in FYs 2001 and 2002, to \$6 million in FY 2003, to \$750,000 in FYs 2004 through 2006. The current appropriation covers a contract call center and minimal outreach.

## d. Unbundling in Competitive Markets

The PURA provisions on retail competition required that electric utilities, as a part of the process of preparing for competition, separate their competitive business functions from their regulated business function. Retail sales and power generation were to become competitive, and the transmission and distribution of electricity were to remain regulated. The separation, or unbundling, requirement gave the utilities the option of creating non-affiliated companies or affiliated companies owned by a common holding company. Most of the utilities with stranded costs sold their generation assets in order to obtain a market-based valuation of the generation assets that could be used as the basis for recovery of the stranded costs. Today, the structures of the companies in the Texas retail market vary:

• The largest transmission and distribution company, TXU ED is affiliated, through common ownership by a holding company, with the largest power generation company and the largest retail electric provider in the ERCOT market.

- CenterPoint, the transmission and distribution company that operates in the Houston area, does not have any affiliation with a power generation company or retail electric provider.
- The AEP transmission and distribution companies (AEP TCC and AEP TNC) are affiliated, through common ownership by a holding company, with a small retail electric provider that serves commercial and industrial customers.
- TNMP is a small transmission and distribution company that is affiliated, through common ownership by a holding company, with a small power generation company and retail electric provider.

The combination of size and common ownership of electric companies in the retail market has created customer confusion that may have deterred customers from switching to competitive retail providers. Switching rates for residential customers have been low, compared to rates for commercial and industrial customers. One of the explanations for the low switching rates has been the belief among customers that the TDU would provide better service to customers served by the REP that is affiliated with the utility. Under this recommendation, any electric utility that is under common ownership with large affiliated power generation companies or retail electric providers meeting certain criteria would be required to file a plan with the Commission for divesting these competitive companies.

## Sec. 39.051. UNBUNDLING.

(a)-(g) No change

(h) On or before January 1, 2008, an electric utility that is affiliated with power generation companies that own 5,000 megawatts or more of generating capacity in this state, or retail electric providers that have annual sales of 10,000,000 megawatt-hours or more of electricity in this state shall file with the commission an unbundling plan to discontinue the utility's affiliation with power generation companies and retail electric providers, within a reasonable time determined by the commission.

## **B.** LEGISLATIVE CLARIFICATIONS

## 1. Procedural Clarification: Commission's Deliberation Concerning Confidential Information

In executing its duties under PURA, the Commission is often required to examine information that is confidential by law or otherwise excepted from public disclosure under the TPIA. See, TEX. GOV'T. CODE ANN. Chapter 552 (West 2004). Additionally, PURA §39.001(b)(4) declares that it is in the public interest to protect the competitive process "in a manner that ensures the confidentiality of competitively sensitive information." As a result of the move to competitive markets in the Texas electric industry, the Commission has seen a very large increase in the amount of information reviewed by the Commission for which a claim of confidentiality is asserted. The Commission also has agreed to act as the Hearing Body in enforcement proceedings

for the ERCOT region related to electric reliability standards under EPAct.<sup>94</sup> FERC has adopted rules implementing EPAct that require that certain information be treated as "nonpublic information" during the hearing process, including information that relates to a Cybersecurity Incident or that would jeopardize the security of the bulk power system if publicly disclosed.

There is no provision in the Open Meetings Act (TEX. GOV'T CODE ANN. Chapter 551 (Vernon 2006)) allowing a state agency to hold a closed meeting or executive session to consider information that is excepted from disclosure under the TPIA. The Attorney General has held that there is no implied authority in the Open Meetings Act for an agency to meet in executive session to consider information that is excepted from disclosure under the TPIA do not permit a closed session where none is authorized by law.<sup>95</sup> The Attorney General has also held that the Administrative Procedure Act creates an exception to the Open Meetings Act for "contested cases" so that claims of privilege may be reviewed in a closed meeting.<sup>96</sup> The claim must be made during the course of a contested case and resolution of the claim must require examination and discussion of the allegedly privileged information. The Attorney General stated, "Only that portion of the deliberations which would reveal the information can be closed; the remainder must be held in public."<sup>97</sup> If the claim can be deliberated and decided in public without disclosing the information, the meeting must be open to the public.

The Commission is currently operating as required by law but is concerned that the proliferation of confidential information may inhibit its ability to discuss confidential information without revealing its content. The Commission notes that some regulatory agencies have been granted express authority to conduct closed meetings to consider information that is confidential by law. See, *e.g.*, TEX. GOV'T CODE ANN. §§551.079 and 551.081 (Vernon 2006). The Commission recommends amending PURA to make it clear that the Commission has the authority to conduct a closed meeting to deliberate on matters involving confidential information.

## Sec. 14.051. PROCEDURAL POWERS.

(a) The commission may:

- (1) call and hold a hearing;
- (2) administer an oath;
- (3) receive evidence at a hearing;
- (4) issue a subpoena to compel the attendance of a witness or the production of a document; and

- <sup>95</sup> AG Opinion Nos. MW-578 and GA-0019.
- <sup>96</sup> AG Opinion No. JM-645.
- <sup>97</sup> *Ibid.*, p. 6.

<sup>&</sup>lt;sup>94</sup> FPA, 16 USC §8240.

(5) make findings of fact and decisions to administer this title or a rule, order, or other action of the commission.

(b) Notwithstanding Government Code Chapter 551, the commission may conduct a closed meeting to receive information that it determines is excepted from disclosure under Government Code Chapter 552 and to deliberate concerning the information. A representative of a party to a commission proceeding shall be allowed to attend the closed meeting, provided that the representative complies with the commission's protective order prohibiting public disclosure of the information. The commission may limit the number and types of party representatives that are given access to the information and who are allowed to attend the closed meeting. Only that portion of the hearing during which the information is discussed may be closed to the public. A final action, decision, or vote on the matter deliberated in a closed meeting may only be made in an open meeting held in compliance with Government Code Chapter 551.

## 2. Substantive Clarifications

## a. Voluntary RECs and the Renewable Energy Mandate

In the rulemaking proceedings dealing with implementation of Senate Bill 20, the Commission has encountered considerable controversy with respect to PURA §39.904(m). This new provision requires the Commission to ensure that all RECs "awarded, produced, procured, or sold from renewable capacity in this state are counted toward the goal" in PURA §39.904(a). Parties have taken widely divergent positions on what this provision means and its implications for the renewable energy program.

Under current Commission rules, RECs must be retired by a REP as a part of the renewable energy mandate. In addition, a REP that offers voluntary renewable energy service to its customers must retire RECs to demonstrate that it has bought renewable energy to supply these customers. Using the RECs in this manner provides a simple, cost-effective way of validating the accuracy of the REP's claims. The amount of RECs that must be retired to meet the statutory goal is based on the level of the goal in each year, and the amount of RECs that must be retired to verify a voluntary renewable energy service is based on the nature of the service and how much of it a REP sells. The total number of RECs that must be retired is the sum of these two amounts. (The figure below shows how much renewable capacity has been used to satisfy the mandate, how much has been used to meet voluntary customer demand for renewable energy, and the annual surplus.) One interpretation of PURA §39.904(m) would apply RECs that are retired to verify a voluntary renewable energy service also toward compliance with the statutory goal. As a result, the REPs would be required to retire a smaller number of RECs, so that the number of RECs in demand would be smaller and, presumably, their value would be lower. Commission Staff estimates that the total demand for Texas RECs could vary by 22% to 26% in 2007, depending on the interpretation of this provision.



Figure 22: Use of Renewable Energy Generating Capacity in Texas

Annual REC retirements were converted to capacity equivalents using the capacity conversion factor in effect that year. Surplus is the annual difference between the number of RECs produced, and the number of RECs retired either for the mandate or for voluntary demand. Demand for 2006 is estimated.

The Commission has received many comments objecting to this outcome. In addition, the U.S. Environmental Protection Agency has indicated it would no longer be able to accredit the emission benefits of any voluntary renewable energy service that relied on Texas RECs if the statute were applied in this manner.

The Commission's implementation of PURA §39.904(m) would be aided by the Legislature's clarification of this provision. The Commission recommends that the Legislature adopt one of the two following amendments:

## Alternative 1 (Voluntary REC retirements do not count toward goal)

#### Sec. 39.904. GOAL FOR RENEWABLE ENERGY.

(a)-(l) No change

(m) Notwithstanding any other provision of law, the commission shall ensure that all renewable capacity installed in this state and all renewable energy credits awarded, produced, procured, or sold from renewable capacity in this state are counted toward the goal in Subsection (a). All renewable energy credits that are retired for purposes other than to meet the requirements of Subsection (c)(1) shall not affect the minimum annual renewable energy requirement pursuant to Subsection (c)(1) for any retail electric provider, municipally owned utility, or electric cooperative.

(n) No change

## Alternative 2 (Voluntary REC retirements do count toward goal)

#### Sec. 39.904. GOAL FOR RENEWABLE ENERGY.

(a)-(l) No change

(m) Notwithstanding any other provision of law, the commission shall ensure that all renewable capacity installed in this state and all renewable energy credits awarded, produced, procured, or sold from renewable capacity in this state are counted toward the goal in Subsection (a). <u>All renewable energy credits retired for any purpose shall be used in establishing compliance with the minimum annual renewable energy requirements pursuant to Subsection (c)(1).</u>

(n) No change

## b. Commission's Determination of Competitively Sensitive Information

Transparency of pricing information is an important aspect of a healthy wholesale electricity market. As in other markets, the disclosure of pricing information will allow greater competition among market participants and should result in lower prices to retail consumers. Disclosure will also help to assure consumers that wholesale prices are not the result of market manipulation or market power abuse. In order to provide the necessary disclosure on a non-discriminatory basis, it is important that the Commission's power to require disclosure by all market participants is more expressly stated. Questions have been raised about the Commission's authority under current law, and it would be desirable to obviate these questions by the enactment of legislation that gives the Commission explicit authority in this area.

Under PUC SUBST. R. 25.93(g), relating to Quarterly Wholesale Electricity Transaction Reports, the Commission may decide whether information submitted to it by wholesale sellers of electricity must be treated as confidential by the Commission and its Staff. The rule provides that if the Commission Staff seeks to release protected information, and there has been no request for the information under the TPIA, the Commission may determine the validity of the asserted claim of confidentiality through a contested-case process. The rule was adopted by Commission order published in the *Texas Register* on September 5, 2003.<sup>98</sup>

On September 19, 2003, several cities sued the Commission in the Third Court of Appeals claiming, among other things, that the Commission exceeded its authority in promulgating Subsection 25.93(g). The cities claimed that PURA does not authorize the Commission to determine, as a matter of fact, whether information is "competitively sensitive" as that term is used in PURA. On May 19, 2005, the Austin Court of Appeals issued its decision in *City of Garland et al. v. Public Util. Comm'n of Texas*, 165 S.W.3d 814 (Tex. App. – Austin 2005, pet. denied). The Court invalidated Subsections (c)(2) and (g)(3) of the rule, holding that the Commission's rule contravened the exception to public disclosure for "public power utility competitive matters" contained in the TPIA and the procedure specified in the TPIA to contest a public power utility's claim that information is competitively sensitive. See TEX. GOV'T. CODE ANN. §552.133 (West 2004). The Court did not express an opinion on the Commission's power to determine

<sup>&</sup>lt;sup>98</sup> PUC Rulemaking Concerning Disclosure of Information Related to Electricity Transactions Originating or Terminating in Texas, Project No. 26188, Order Adopting New §25.93 (Aug. 15, 2003).

for itself other claims of confidentiality, including assertions based upon other TPIA exceptions.

In PUC SUBST. R. 25.505, relating to Resource Adequacy in the Electric Reliability Council of Texas Power Region, the Commission asserted authority to require ERCOT to publish resource and load information provided to it by those entities that participate or schedule energy in ERCOT day-ahead or real-time energy and ancillary services markets. Subsection 25.505(f)(3) of the rule provides that ERCOT must publish entity-specific information on offers into ERCOT real-time energy and ancillary services markets and other entity-specific information within 30 to 90 days after the information was compiled. Additionally, information identifying the highest bid and the entity making the bid during each interval is required to be posted within 48 hours after the information was collected. Some of the disclosure portions of the rule were challenged by some market participants contending that the Commission lacked authority to determine whether the information was confidential information that was exempt from disclosure under PURA and the TPIA. See Constellation Energy Commodities Group, Inc. v. Public Utility Commission of Texas, No. 03-06-00552-CV, (Tex. App. - Austin) (direct appeal of a competition rule). The City of Garland also challenged the disclosure provisions, claiming that they contravened the TPIA and the prior decision in the *City of Garland* case, *supra*. See *City* of Garland v. Public Utility Commission of Texas, No. 03-06-00571-CV, (Tex. App. -Austin) (direct appeal of a competition rule). The market participants who filed the initial challenge then amended their claims to also contend that imposing disclosure requirements for cities that are different from the requirements imposed on all other market participants would be discriminatory. On September 29, 2006, the Court of Appeals issued Orders in both cases staying implementation of the disclosure requirements of PUC SUBST. R. 25.505(f)(3) pending further orders from the Court. A briefing schedule has been established and a ruling on the merits is expected in 2007.

The Commission notes that the exception from disclosure for "public power utility competitive matters" was added to the TPIA to prevent such entities from being at a competitive disadvantage. Without the exception, they would have been required to disclose competitive matters because such matters would be "public information" under the TPIA, while the private entities with whom they compete would be under no obligation to disclose similar information. Instead, as a result of the *City of Garland* decision, municipal utilities have broad authority to prevent the disclosure of information, and other market participants are arguing that they should also be exempt from such disclosure. This situation impedes the Commission's efforts to require the necessary flow of information that is important for the efficient operation of a dynamic wholesale market. The Commission recommends amending PURA to make it clear that the Commission has the authority, as part of a Commission proceeding, to evaluate an asserted claim of confidentiality.

## Sec. 39.001. LEGISLATIVE POLICY AND PURPOSE.

(a)-(f) No change

<sup>(</sup>g) For any information required by this Subtitle to be provided to the commission, the independent organization, or the independent market monitor, a market participant may assert a

claim that the information is competitively sensitive information or is exempt from disclosure under Chapter 552 of the Government Code. On its own motion or in response to a request for disclosure of the information, the commission may review such claims in a commission proceeding. If the commission determines that such information is not competitively sensitive information; is not subject to an exemption under Chapter 552 of the Government Code; and that release of the information is in the public interest, the commission may, by rule or order, declassify the information and make it publicly available. The commission may adopt rules establishing the types of information that qualify as competitively sensitive information under this Subtitle.

## c. Implementation of Retail Competition in Non-ERCOT Areas

Chapter 39 of PURA allowed the Commission to delay retail competition in areas that were not able to offer fair competition and reliable service to all retail customer classes on January 1, 2002, but some provisions of PURA establish dates for events that are related to the introduction of retail competition that are based on a January 2002 date for initiating competition. The specificity of these dates causes confusion regarding the Commission's authority to set dates for events in areas where competition has been delayed. The Commission's authority should be clarified to ensure that it may adjust the dates for other important events, where it establishes a different date for the beginning of retail competition.

While most of Texas has retail competition because it is located within ERCOT, the remaining areas of the state are in three other power regions in which retail competition has been delayed, either by action of the Commission or by legislation. The area served by EPE is located in WECC. The service areas of SPS and SWEPCO, as well as a portion of the service area of AEP TNC, are located in SPP. Finally, the EGSI service area is located in the Southeastern Electric Reliability Council (SERC).

Chapter 39 of PURA envisioned that all areas of Texas would be able to begin retail customer choice beginning January 1, 2002, and retail customer choice began as scheduled in ERCOT. PURA §39.103 authorized the Commission to delay customer choice in a power region if the Commission determined that the power region was not able to offer fair competition and reliable service to all retail customer classes on January 1, 2002. Because the areas in the remaining power regions have not been able to meet the required standard, the implementation of retail competition has been delayed in those areas.

In November 2004, the Commission adopted PUC SUBST. R. 25.421, which delays the implementation of retail customer choice in the EPE service area until the completion of a five-stage process designed to develop the necessary conditions for ensuring fair competition and reliable service for all customer classes.<sup>99</sup> In September 2006, the Commission adopted PUC SUBST. R. 25.422, which established a similar four-stage process for initiation of retail competition in the SWEPCO service area and the SPP

<sup>&</sup>lt;sup>99</sup> Project No. 28971, *loc. cit.* 

service area of AEP TNC.<sup>100</sup> This rule also provides that retail competition will be delayed until January 1, 2011, at the earliest.

Pursuant to PURA Subchapter I, retail competition has been delayed in the SPS service area "until the later of January 1, 2007, or the date on which an electric utility subject to this subchapter is authorized by the commission to implement customer choice." Because SPS is located within the SPP power region, it is subject to the same impediments to implementation of customer choice that face SWEPCO. It is unlikely that it will be able to implement customer choice earlier than the timeframe currently contemplated for SWEPCO.

Pursuant to PURA Subchapter J, implementation of customer choice in the EGSI service area is delayed until EGSI "is authorized by the commission to implement customer choice." EGSI is required to file a transition to competition plan with the Commission by January 1, 2007, identifying how it will achieve full customer choice, including the certification of the applicable power region as a qualifying power region under PURA §39.152(a). Efforts to implement retail customer choice in EGSI's current power region, SERC, have virtually ceased. As part of its January 1, 2007 transition to competition plan, EGSI is considering joining either ERCOT or the SPP. Joining either of these power regions could help EGSI achieve full customer choice, but the construction of necessary transmission infrastructure would likely delay customer choice until 2010 or later in EGSI's service area.

In addition to these areas, implementation of customer choice has been delayed in the Cap Rock service area. Cap Rock has portions of its service area in both ERCOT and SPP. At the time customer choice was implemented in ERCOT, Cap Rock was exempted from the requirements of implementing customer choice pursuant to PURA provisions that enabled it to be treated as an electric co-operative. In 2003, the Legislature repealed the exemption for Cap Rock and added PURA §39.102(d) and (e), requiring the Commission to establish schedules and procedures for Cap Rock to achieve the objectives of Chapter 39.

If retail competition is to be implemented in these areas where it is not in effect today, the Commission will need to require unbundling of the existing utilities, the establishment of UCOS rates, the establishment of price-to-beat rates, and other steps contemplated by the Legislature. However, the legislative requirements for the implementation of customer choice are so specific that they may inhibit the Commission's efforts to bring customer choice to these non-ERCOT areas in the future. For example, PURA §39.201 requires the filing of cost of service tariffs and charges on April 1, 2000, and the transmission and distribution rates must be based upon a "forecasted 2002 test year." Additionally, the price to beat is required by PURA §39.202 to be calculated based upon a 6% reduction to the rates "that were in effect on January 1, 1999." The requirement to set rates based on 1999 or 2002 conditions is not reasonable in establishing rates in 2007 or later, particularly when some of these utilities have had, or will have had, rate changes

<sup>&</sup>lt;sup>100</sup> Project No. 32104, *loc. cit.* 

implemented since 2002. The Commission recommends amending PURA to clarify that the Commission has the authority to establish standards and schedules for implementing retail customer choice in areas where choice is not currently available.

#### Sec. 39.1035. COMMISSION AUTHORITY TO IMPLEMENT COMPETITION IN AREAS WHERE COMPETITION HAS BEEN DELAYED.

In any area in which the implementation of customer choice has been delayed by commission action or by this chapter, the commission may establish a schedule for implementation of full customer choice in a manner that achieves the objectives of this chapter. Notwithstanding any other provision of this chapter, in considering an application to implement customer choice in an area where it is not available as of December 31, 2006, the commission may:

(1) establish the appropriate test year for establishing any rates required by this chapter, provided that the test year may not begin earlier than two years prior to the filing of the application and may not be forecasted more than two years beyond the filing of the application;

(2) establish the appropriate price to beat based upon the rates most recently approved by the commission;

(3) establish the appropriate price to beat fuel factor; and

#### (4) make other appropriate adjustments to the dates specified in this chapter.

#### Sec. 39.402. REGULATION OF UTILITY AND TRANSITION TO COMPETITION.

(a) Until the later of January 1, 2007, or the date on which an electric utility subject to this subchapter is authorized by the commission to implement customer choice, the rates of the utility shall be regulated under traditional cost of service regulation and the utility is subject to all applicable regulatory authority prescribed by this subtitle and Subtitle A, including Chapters 14, 32, 33, 36, and 37. Until the date on which an electric utility subject to this subchapter implements customer choice, the provisions of this chapter, other than this subchapter, **Sections 39.1035 and** 39.904, and the provisions relating to the duty to obtain a permit from the Texas Natural Resource Conservation Commission for an electric generating facility and to reduce emissions from an electric generating facility, shall not apply to that utility. That portion of any commission order entered before September 1, 2001, to comply with this subchapter shall be null and void.

(b)-(d) No change

#### Sec. 39.452. REGULATION OF UTILITY AND TRANSITION TO COMPETITION.

- (a)-(c) No change
- (d) Until the date on which an electric utility subject to this subchapter implements customer choice:

(1) the provisions of this chapter do not apply to that electric utility, other than this subchapter, Sections <u>39.1035</u>, 39.904 and 39.905, the provisions relating to the duty to obtain a permit from the Texas Commission on Environmental Quality for an electric generating facility and to reduce emissions from an electric generating facility; and

(2) the electric utility is not subject to a rate freeze and, subject to the limitation provided by Subsection (b), may file for rate changes under Chapter 36 and for approval of one or more of the rate rider mechanisms authorized by Sections 39.454 and 39.455.

(e)-(h) No change

# **APPENDIX: ACRONYMS**

AEP	American Electric Power
AEP TCC	AEP Texas Central Company
AEP TNC	AEP Texas North Company
AEP-TNC-SPP	Southwest Power Pool portion of the AEP Texas North Company service area
AREP	affiliated retail electric provider
BPL	Broadband over Powerline
Cap Rock	Cap Rock Energy Corporation
CCN	Certificate of Convenience and Necessity
CenterPoint	CenterPoint Energy Houston Electric, LLC
CPL	CPL Retail Energy
CREP	competitive retail electric provider
CREZ	competitive renewable energy zone
CTC	competition transition charge
EGSI	Entergy Gulf States, Inc.
EIS	Energy Imbalance Services
EPAct	federal Energy Policy Act of 2005
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ERO	electric reliability organization
FERC	Federal Energy Regulatory Commission
ICE	Intercontinental Exchange
IMM	Independent Market Monitor
IPP	independent power producer
kWh	kilowatt-hour
LITE-UP	Low-Income Telephone and Electric Utilities Program
LNG	liquefied natural gas
MCPE	Market Clearing Price of Energy
MCSM	Modified Competitive Solution Method
ME SPP	Mutual Energy SWEPCO, LP d/b/a Mutual Energy SPP
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Council
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NUS	non-unanimous settlement
NYMEX	New York Mercantile Exchange
OOMC	Out-of-Merit Capacity

OOME	Out-of-Merit Energy
OPUC	Office of Public Utility Counsel
PGC	power generation company
PNM	PNM Resources, Inc.
POLR	Provider of Last Resort
PSA	public service announcement
PTB	price to beat
PURA	Public Utility Regulatory Act
QSE	qualified scheduling entity
REC	Renewable Energy Credit
REP	retail electric provider
RMO	Retail Market Oversight Section of PUC's Electric Industry Oversight Division
RMR	Reliability-Must-Run
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SBF	System Benefit Fund
SERC	Southeastern Electric Reliability Council
SOAH	State Office of Administrative Hearings
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company
TCEQ	Texas Commission on Environmental Quality
TDU	transmission and distribution utility
TNMP	Texas-New Mexico Power Company
TPIA	Texas Public Information Act
TXU ED	TXU Electric Delivery Company
UCOS	unbundled cost of service
WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council
WMO	Wholesale Market Oversight Section of PUC's Electric Industry
	Oversight Division
WTU	WTU Retail Energy