Report to the 81st Texas Legislature

Scope of Competition in Electric Markets in Texas

Public Utility Commission of Texas
January 2009

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THE STATE OF TEXAS

Public Utility Commission of Texas

Rick Perry
Governor

January 15, 2009

Honorable Members of the Eighty-First Texas Legislature:

We are pleased to submit our 2009 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act (PURA). 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 other electric industry responsibilities under State law. The report concludes with a discussion of emerging issues and recommendations that the Legislature may want to consider.

Despite volatile electric power prices influenced primarily by volatile natural gas prices, Texas has realized many market successes in the past two years. The State of Texas continues to be a leader in the implementation of a competitive electric market and a world leader in renewable wind energy. Only four other countries - Germany, Spain, India, and China - have more wind generation capacity than Texas. The Commission's designation of Competitive Renewable Energy Zones (CREZ) in Texas and approval of a transmission plan for these zones represents one of the largest electric infrastructure developments in the nation; it is an achievement that many states and/or regions are attempting to emulate. Advanced metering, which is commencing deployment in Texas, promises to improve the operation and reliability of our transmission and distribution infrastructure, benefiting customers and reducing costs in the electricity market. At the same time, the Texas electric industry has been successful in attracting capital for investment in generation, delivery facilities, and retail and energy-efficiency services.

This report also includes additional information requested by the Legislature on the issues of CREZ development, renewable generation, system reliability, and transmission and generation (PURA § 39.904 (j) and (k)) and the impact of renewable energy development under PURA § 39.904 on market power and electricity rates paid by residential customers (HB 1090). We look forward to continued collaboration with the Legislature as we secure a bright energy future for electricity customers, commerce, and industry in Texas. If you need additional information about any issues addressed in this report, please contact us.

Sincerely,

Barry T. Smitherman	Donna L. Nelson	Kenneth W. Anderson, Jr.
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Acknowledgements

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I. Introduction and Executive Summary

The Public Utility Commission of Texas (Commission) has seen many challenges since its last report on the scope of competition in electric markets. This report outlines important trends in the industry and the activities that the Commission has undertaken to continue implementing retail and wholesale competition in the sale of electricity. The introduction highlights important activities and events that have occurred in the last two years: volatile natural gas and electricity prices, the transition to a nodal market, development of a competitive renewable energy plan (CREZ), advanced metering implementation, energy efficiency measures, the response to Hurricane Ike, possible effects of carbon legislation on Texas, the recessionary economic environment, and the State Energy Plan.

Volatile Natural Gas and Electricity Prices

Since retail competition began in 2002, market prices for power have increased at both the wholesale and retail level, primarily due to increases in the price of natural gas used to fuel electric generation. In the summer of 2008, monthly natural gas price futures closed at a high of $12.78, more than five times higher than the January 2002 closing price of $2.19. [1] This rise in natural gas prices resulted in higher wholesale electric prices over the same period. Conversely, in the latter half of 2008, natural gas prices fell from summer highs of over $13. The January 2009 contract settled on December 10th at $5.686 per MMBtu and, as of printing, natural gas futures continue to fall.

The magnitude of the changes in natural gas prices has been much larger than the changes in electricity prices. While gas prices more than tripled over a period of less than six years, competitive residential electricity prices, because of large offer spreads, remained steady or only doubled over the same period. For example, residential offers in the Oncor service area during the second week of November 2008 ranged from 10.9 cents to 19.9 cents per kilowatt-hour (kWh). The lowest fixed price contract offered by the regulated utility in the Oncor service area in 2001 was 9.7 cents per kWh.

Customers have the ability to insulate themselves from price increases if they buy long-term, fixed-price contracts. However, this strategy has some risks. Long-term contracts may expire at a time when retail prices are high, and the customer may then face much higher prices. In addition, a small percentage of customers with fixed price contracts had their retail electric provider (REP) leave the market, and the customers lost the benefit of their fixed-price contracts.

[1] Monthly Natural Gas Futures Contract 1; Energy Information Administration, US Department of .Energy

In May and June 2008, the Electric Reliability Council of Texas (ERCOT) region experienced very high prices in the wholesale electricity market caused by a multitude of factors: unusually high temperatures during a time when a number of power plants and power lines were out of service for maintenance, high natural gas prices, and severe transmission congestion on two interfaces. Pursuant to the Commission's order in Docket No. 33490, the cap on wholesale prices rose to $2,250 on March 1, 2008. The ERCOT Wholesale Market Subcommittee increased the shadow-price cap to $5,600 in an effort that resulted in balancing energy prices rising above the Commission offer cap for numerous intervals. The Commission acted promptly and directed ERCOT to address the congestion and adjust the shadow-price cap. Further discussion on the shadow price cap can be found in the Wholesale Market Oversight section of this report.

Also during this period of high electricity prices, four retail electric providers (REPs) were unable to meet their obligations to ERCOT and went out of business. Their customers were transferred to providers of last resort (POLRs). Customers and REPs serving as POLRs expressed frustration and disappointment in the POLR process. Many of the customers were unable to obtain refunds of deposits they paid to their original REP, and the REPs to which they were transferred typically requested deposits to serve them. In addition, many of the customers lost the benefit of low-price fixed contracts with a REP that left the market, while the prices they faced for POLR service or a competitive service were much higher. Some customers were unable or unwilling to pay an additional deposit. The POLR REPs provided service to some customers for a period and then terminated the customer's service for non-payment of the deposit. Many unhappy customers switched away from the POLR REP without paying their bills and some POLR REPs experienced large uncollectible expenses during this period. As a result of this experience, the Commission is proposing amendments to three of its major retail market rules, those dealing with REPs' disclosures to customers, standards for entering the retail market, and provider of last resort service.

Preparations for the Nodal Market

In 2005, the Commission directed ERCOT to implement a nodal market design, in place of the current zonal design, to improve efficiency in the wholesale market. The nodal market was to begin operating in January 2009. In the summer of 2008, ERCOT announced the nodal market implementation would be delayed. In September 2008, the Commission directed ERCOT to contract for an updated cost-benefit analysis (CBA) to assess whether the transition to a nodal market is still beneficial. The first nodal budget of $263 million was approved by the ERCOT Board of Directors in January 2007 with a board approved-revision to $319 million in January 2008. Testimony filed by ERCOT in November 2008 indicates the preliminary budget for completion of the nodal project has increased to $660 million, and the expected date for initiating the nodal market is December 2010. The preliminary budget and market "go live" date are not official, because they have not been approved by the ERCOT board of directors or the Commission.

CREZ Transmission Plan

In October 2008, the Commission designated five areas in west Texas as competitive renewable energy zones (CREZs) and identified major transmission improvements necessary to deliver 18,456 MW of renewable resources to customers in other parts of the state. This level of renewable capacity is roughly three times the current renewable capacity in Texas. Texas is already the largest producer of wind energy in the United States and this $4.93 billion investment for transmission in support of wind development represents the most significant investment to date in Texas' clean energy future. The Commission is in the process of selecting the transmission companies to build and operate the new transmission facilities; it expects to make selections by January 2009.

Advanced Metering

As the population in Texas continues to grow, ERCOT forecasts that demand for electricity will increase. Diverse electric generation will be necessary to meet that expected increase. Also important will be tools that empower residential customers to be able to make informed decisions about their electric use. Advanced metering (AMI) provides Texas residential customers several tools to control and reduce their consumption.

For most residential customers in the United States, consumption of electricity is measured with a simple electro-mechanical meter mounted on the side of the house. The meter is read by a technician sent to the residence monthly to inspect the registers in the meter. Advanced meters have the ability to record consumption at shorter intervals, store the consumption information, and transmit the information to the utility's billing system automatically. Advanced metering technology may also include the ability to turn a customer's electric service on or off remotely. The remote control feature can facilitate shorter timelines and greater predictability for initiating or terminating service. Advanced meters also facilitate real-time pricing. Customers can be charged for the price of electricity when they use it instead of paying for an average cost over the course of the month. This pricing approach can result in significant savings for those customers who choose to lower their usage during the times of high electricity prices that occur during peak consumption hours in the middle of the day. Smart consumer devices and appliances may also be able to take advantage of this real-time pricing by communicating with an advanced meter and automatically adjusting their operation in response to electric price changes, saving the customer money.

Advanced metering can yield savings for utilities, improve the efficiency of market processes for retail electric providers and ERCOT, and give retail electric providers a platform for new electric service offers that will benefit customers. Although AMI has a cost, the initial and ongoing costs of AMI are expected to be relatively modest, and can be offset by a combination of operational savings to the utility and electricity savings to retail customers. Advanced meter deployment plans filed by both Oncor and CenterPoint Energy were approved in 2008.

Energy Efficiency

Legislation enacted during the 80th Legislative Session, modified the utility energy efficiency program the Commission oversees by raising the electric utilities' energy efficiency goals from 10 percent of growth in demand to 15 percent of growth in demand by January 2009 and 20 percent of growth in demand by January 2010. The Commission was also authorized to adopt a cost recovery mechanism and performance bonuses for energy efficiency programs. At the end of calendar year 2007, the transmission and distribution utilities responsible for implementing energy-efficiency programs exceeded their demand goals by 25 percent and saved nearly 371,459 MWh of energy. In 2008, the Commission adopted a new rule to implement these goals; it also included an energy-savings goal for utilities, a capacity goal, and granted them broader latitude in developing programs to meet these goals. The Commission hired consultants to conduct an energy-efficiency study and a study of combined heat and power technology. These reports will be delivered to the legislature in January 2009, as required by the new legislation.

Hurricane Ike

Hurricane Ike made landfall on Saturday, September 13, 2008, on Galveston Island as a Category 2 hurricane with 110 mph winds and a 12-foot storm surge. After the storm hit, nearly 2.87 million customers were without power and 366 transmission lines were out throughout Texas. The utilities in the state were prepared for the hurricane and a total of 15,235 line-crew personnel from the affected utilities and mutual assistance personnel from utilities in Texas, over 25 other states and Canada were called to impacted areas to assist with the restoration efforts. By September 27th, 100 percent of power was restored to the Texas-New Mexico Power service territory. Entergy Texas and CenterPoint Energy reached 100 percent restoration on September 30th and October 1st, respectively.

Besides damage to homes, businesses, and infrastructure, the devastation from Hurricane Ike also resulted in significant financial losses for transmission and distribution utilities and REPs. The transmission and distribution utilities incurred costs for the restoration and repair of facilities that will exceed the storm reserves and insurance they have available. REPs also suffered financial losses because they were unable to deliver to their customers the power they had bought to serve them. Reliant Energy, for example, reported that Hurricane Ike was a primary cause of lower cash flow in the third quarter of 2008, because of lower sales volume and losses from the resale at a loss of power acquired for customers. If securitization legislation similar to House Bill 624 passed in 2007 for Hurricane Rita were passed for Hurricane Ike, transmission and distribution utilities could securitize such costs. As with other securitized amounts, the charges related to recovery of these costs would be passed on to retail electric providers in the form of a nonbypassable charge.

Carbon Legislation

Data from the U.S. Energy Information Administration (EIA) show that the electric power industry in Texas accounts for about 37 percent of total Texas carbon dioxide, CO_2, emissions.[2] Texas relies heavily on coal and natural gas for the production of electricity, although it relies less on coal than many other states. In ERCOT, coal and natural gas represent 91 percent of installed generating capacity and 81 percent of the energy consumed.

Several bills have been proposed at the national level to regulate greenhouse gases (GHG), primarily CO_2. None of the bills are expected to be adopted in the current Congress, but carbon regulation is likely to be a priority issue in the next Congress. The Lieberman-Warner Security Act of 2007 (S. 2191/3036) was debated in the Senate and would rely primarily on a market-driven cap and trade system to reduce the 2005 GHG emission level by 15 percent by 2020, 30 percent by 2030, and 70 percent by 2050. Entities covered by the program, including electric generators, would be required to submit emission allowances for each ton of CO_2 emitted during the year, and the supply of available allowances would decline over time, consistent with the emission-reduction goals.

Chairman Smitherman recently served on a panel appointed by Governor Perry that analyzed the potential impact to Texas of regulating carbon emissions. The panel concluded, "A large portion of man-made CO_2 in Texas is created by electric generation. Traditional coal-fired electric production emits more CO_2 than all other forms of electric generation. Reductions in CO_2 will likely be achieved by reducing coal-produced electricity, resulting in less fuel diversity, higher reliance on natural gas, decreased electric reliability, and higher prices for customers. With energy demand in Texas expected to increase 31 percent by 2025, eliminating coal (the second largest source of power) will certainly be devastating to the state economy."[3]

Recessionary Economic Environment

Although the electric industry is generally less sensitive to recessionary economic conditions than many other industries, maintaining financial flexibility and access to capital has been increasingly challenging for utility companies and competitive electric companies with the volatile capital-market conditions that have prevailed during much of the last six months. Because of its capital-intensive nature, the electric industry relies heavily on ready access to debt and equity markets. In the wake of recent market instability, electric companies across the country have experienced credit-rating

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[2] http://www.eia.doe.gov/environment.html

[3] *Potential Impacts to Texas of the Environmental Protection Agency's Proposed Framework for Regulating Greenhouse Gas Emissions*, Texas Advisory Panel On Federal Environmental Regulations; Nov 25, 2008. p 1.

downgrades and "negative" rating outlooks that have notably outpaced upgrades and positive outlooks.

Reflecting the difficult economic environment, electric utilities' capital costs have been rising. For utility companies rated "BBB" (the lowest investment-grade rating, and the rating of most investor-owned utilities in Texas), debt costs in November 2008 exceeded nine percent, an exceptionally sharp increase over the approximately six percent rates on comparable BBB securities from a year earlier. The cost of debt is beginning to approach regulated returns on equity, which in recent years have been trending downwards to the 10 percent benchmark and, in some cases, have even dipped slightly below this figure. Going forward, if current costs of utility debt continue to prevail, correspondingly higher authorized returns on equity will likely be required to attract additional capital.

Deteriorating conditions in the credit markets have also placed significant pressure on the financial strength of retail electric providers, who must maintain reliable access to capital to satisfy their collateral requirements and maintain compliance with Commission and ERCOT financial standards. Moreover, as the effects of a weak overall economy have filtered down to consumers, retail providers have begun to experience a substantially greater incidence of customer non-payment, which further intensifies pressure on earnings and exacerbates the potential for serious liquidity problems. While smaller retail providers may in some respects face greater exposure to volatile market conditions because their access to a variety of credit sources is generally more limited, the state's largest retail electric providers are also vulnerable—and for these larger providers, the potential market-wide consequences of serious financial difficulties are far more severe.

Another critical issue the industry is likely to face is greater difficulty in planning for capital expenditures. The development of strategic forecasts for the construction of new generation facilities and transmission facilities will, with greater market uncertainty, become increasingly problematic. One area in which this problem may be most acute is in the planning and construction of nuclear generation facilities. The extremely high cost of building a nuclear plant requires reliable and financially sound sources of capital. In an unstable market environment, not only is the availability of such financing a critical concern, so too are the higher financing costs that result from the greater perceived risk of constructing a nuclear plant.

Credit considerations impact not only the builders of traditional generation capacity, but also the developers of renewable energy capacity. The combination of weak capital markets and fuel-price volatility (especially low natural gas prices) creates forecasting uncertainties and brings into question the economic viability of higher-cost alternative energy sources. Wind, for example, loses much of its economic attractiveness as traditional fuel prices moderate from the high relative levels that prevailed during early 2008. Fuel price have fallen, largely as a consequence of recession conditions in North America and abroad, and the expectation is that when underlying economic conditions improve, fuel costs will increase. Should prices remain at modest levels or continue to fall, the degree of certainty associated with planned investments in wind generation capacity can be expected to commensurately decrease.

In view of these factors, power generation companies and integrated utilities will need to take a close look at their planning activities with respect to both the size and type of generation capacity expected to be economic in the future. Ultimately, such decisions will depend not only upon conditions in the capital markets, but also upon expectations about future price levels of commodities such as steel and other construction materials and, perhaps most importantly, fuel (and in Texas, the price of natural gas in particular).

Governor's Competitiveness Council Energy Plan

In November 2007, Governor Perry appointed 29 public and private sector leaders to the Governor's Competitiveness Council. Among these leaders was Chairman Smitherman of the Commission. The council was established to identify competitiveness issues and opportunities in six targeted industry clusters. The six industry clusters addressed were energy, petrochemicals, aerospace and defense, advanced technologies and manufacturing, biotech and life sciences, and computer and information technology.

The Competitiveness Council submitted a report and energy plan to the Governor, and he endorsed both, stating that the council reports provide a road map for the Governor, State Legislature, state agencies and industry leaders to enhance Texas' competitive position in the global economy. Pertinent recommendations from the 2008 State Energy Plan are incorporated into the legislative recommendations in this report.

II. Summary of Commission Activities from 2007 to 2009 to Reflect Changes in the Scope of Competition in the Electric Industry

A. Rulemaking Activities

1. Major Retail Market Rulemakings

a. One-Time Bill Payment Assistance

The System Benefit Fund (SBF) provides electric payment assistance to low-income customers and funds customer education programs administered by the Commission. During the 79th Legislature, PURA §39.903 was amended to permit the SBF to be used to provide electric bill payment assistance to customers who have been threatened with disconnection of their electric service for non-payment and who are, or have in their households a person who is, low-income and seriously ill or disabled.

In 2008, the Commission adopted rules governing the bill payment assistance program.[4] An eligible electric customer will receive assistance one time per state fiscal year, with a limit of the lesser of $1,000 or the outstanding balance from the customer's last three months' electric bills. The bill payment assistance program was not implemented during the current biennium because funds were not appropriated for it during the 80th Legislature. The Legislature funded the rate reduction program for the summer months of the biennium, with $80 million in FY 2008 and $90 million in FY 2009. (See part G. Low-Income Discount for summary statistics.)

b. Advanced Metering Implementation

Following the adoption of the advanced metering rule[5] which provided a structure for deployment and cost recovery for AMI, the Commission opened a project to address the implementation of AMI, assessing the impacts on the ERCOT retail and wholesale markets to ensure that customers receive benefits from AMI investments.[6] AMI implementation affects all market segments. Changes to market processes include those governed by Commission substantive rules, ERCOT Protocols and market guides, as well as the data systems of REPs, utilities and ERCOT. In addition, new transactions, modification of existing transactions, new business processes, and new data transport mechanisms may have to be developed to support AMI.

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[4] *Rulemaking to Implement Requirement of PURA §39.903(e)(1)(B) Concerning a One-Time Bill Payment Assistance Program*, Project No. 33811, Order Adopting New §25.455 and Amendments to §25.497 (Jan. 2, 2008).

[5] P.U.C. SUBST. R. 25.130

[6] *Implementation Project Relating to Advanced Metering*, Project No. 34610.

The implementation project has included broad participation from market participants including utilities, ERCOT, Commission staff, vendors, consumers, REPs and others. There are four main areas under consideration as part of the implementation project:

- home area network, which will allow meter data to be accessed in the home;
- access to customer data and related security;
- ERCOT settlement; and
- customer education.

Through the first half of 2008, it was expected that demand for electricity would continue to grow along with the Texas economy. In an environment in which demand for all types of energy was increasing, some analysts forecasted the energy industry needed to prepare for a period of much higher capital expenditures.[7] News accounts from around the United States tell of utilities seeking rate increases, including a request for a 29 percent increase for a Virginia utility, 38 percent for Xcel Energy in Colorado, 25 percent for Public Service Company of Oklahoma, 31 percent for Florida Power & Light in Florida. In Texas, both integrated and non-integrated utilities have also filed for increases: 13.2 percent for Oncor Electric Delivery, 21.6 percent for Entergy, 10 percent for Southwestern Public Service, and 23.8 percent for Texas New Mexico Power.[8] Cambridge Energy Research Associates estimated that $900 billion of direct infrastructure investment would be required by electric utilities over the next 15 years.[9] This $900 billion of new investment compares with the $750 billion of generation, transmission, and distribution currently in place. These rate increase requests and the expectation of future increases are the result of the confluence of several factors:

- Shrinking generation reserve margins, as the surplus capacity diminishes;
- Increases in natural gas prices and differences in fuel mix;
- Increased spending on pollution controls, especially to comply with nitrogen-oxides, sulfur, and mercury requirements;
- The perception that the federal government will enact carbon legislation;
- The need to replace aging transmission and distribution infrastructure, much of which was put in place 30-40 years ago and is nearing the end of its design life;
- Continued robust rates of population growth and economic growth in many parts of the United States, resulting in the need for system expansion; and
- Technology spending on areas such as customer information systems, AMI and smart grid technologies.

To ensure reliability and competitive functioning of markets, Texas needs to ensure an adequate supply of electricity. While that will undoubtedly include the building of new

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[7] "*Banking on the Big Build*", Public Utilities Fortnightly, October 2007, Roger Wood, p 49; and cited with approval in National Regulatory Research Institute report *Private Equity Buyouts of Public Utilities: Preparation for Regulators*, Dec 2007, Stephan G. Hill, p 36.

[8] These percentage increases reflect the increase in rates for an average residential customer with 1000 kWh usage per month.

[9] "*Banking on the Big Build*", Public Utilities Fortnightly, Oct 2007, p 50.

transmission and generation facilities, customers will benefit from demand-response solutions that give them the ability to better understand and control their usage. Energy efficiency and demand-response programs have the potential to meet customers' needs with lower levels of investment in generation, transmission, and distribution facilities. If customers participate in programs to reduce consumption during periods of high demand, then fewer additions to generation, transmission and distribution facilities need to be made. Dynamic pricing programs will encourage customers to reduce demand when wholesale market prices are high and resources are scarce, thereby reducing peak demand and the cost of providing electricity to both customers participating in such programs and those who do not participate.

c. Distributed Renewable Generation

One provision of HB 3693 enacted by the 80th Legislature dealt with metering and interconnection standards for distributed renewable generation (DRG), or net metering.[10] Distributed generation produces electricity at a customer's home or business. The energy from a DRG facility typically can be consumed by the customer or exported to the electric network. HB 3693 requires that ERCOT be capable of accounting for purchases of DRG energy in wholesale settlement no later than January 1, 2009. To meet this requirement, the Commission adopted a rule in April 2008 to establish the terms for metering under this legislation.[11] This phase of the project was expedited, to permit ERCOT to meet the January 2009 deadline.

Historically, the Commission had rules requiring utilities to provide net metering options for qualifying facilities. A qualifying facility is a customer-owned generator that relies on renewable energy or cogeneration to produce energy. In the initial rulemaking phase, the Commission received a large volume of comments from the DRG industry and individuals arguing in favor of a definition of net metering that nets inflows and outflows. This is called a roll-back meter. Roll-back meters have a single register that operates normally when energy is being consumed from the grid, but runs backwards when energy is being exported to the grid, effectively crediting the DRG owner at the retail rate for energy put onto the grid. Because PURA refers to meters that measure outflows and inflows, the Commission concluded that HB 3639 did not permit roll-back meters for the competitive areas in Texas. The Commission expects to complete a second phase of this project during the fourth quarter of 2008 to establish requirements for interconnection, renewable energy credits, and sale of energy from a distributed renewable generator.

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[10] PURA §§ 39.914, 39.916.

[11] *Rulemaking Related to Net Metering and Interconnection of Distributed Generation*, Project No. 34890, adopting Substantive Rule 25.213, Metering for Distributed Renewable Generation (Dec. 22, 2008).

d. Retail Electric Providers

1. Certification of Retail Electric Providers

In 2008, a combination of poor business decisions and high natural gas prices forced several REPs into bankruptcy, removing some customers from their fixed-price contracts and placing them with other providers. As a result of these REP failures, the Commission proposed more stringent financial and technical standards for the certification of retail electric providers.[12] The Commission has the following goals for the proposed rule changes:

- Improve the credit quality of the retail market, by allowing only those companies that meet higher standards for capitalization and risk management expertise to operate as REPs;
- Require additional security for customer deposits to prevent their loss in the event of a REP default;
- Protect the financial integrity of transmission and distribution utilities (TDUs) from REP default by giving TDUs greater latitude to manage their credit risk exposure within limits set by the PUC; and
- Provide meaningful information to the Commission and customers regarding the financial health of REPs by establishing a requirement for each REP to provide a report on its financial condition on a quarterly basis or more often than that if requested by the Commission.

The Commission published the proposed changes for comment by interested persons in November 2008; it expects to evaluate the comments and adopt an amended rule in early 2009.

2. Retail Electric Provider Disclosures to Customers

In connection with the need for proper advertising and enrollment of customers, the Commission is amending its rules on information disclosures and the labeling of electricity products.[13] These revisions are intended to give customers better information about the electricity products that REPs offer to residential and small commercial customers. The Commission's current rule[14] requires REPs to prepare an electricity facts label (EFL) for each residential product. The new rule would revamp the EFL to provide answers to specific questions that customers have when choosing a new electricity product. For example, a customer could clearly find whether the price quoted in the contract will change during the contract term and, if so, how it will change and whether there are early-termination penalties.

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[12] P.U.C. SUBST. R. 25.107, *Certification of Retail Electric Providers*, Project No. 35767

[13] *Rulemaking Relating to Retail Electric Providers Disclosures to Customers*, Docket No. 35768 (pending).

[14] P.U.C. SUBST. R. 25.475

To provide customers better information about the expiration of a contract and a better opportunity to consider the available options, the proposed rule also requires REPs to send notice to customers 60-75 days before their contract expires. The proposed rule would not allow early-termination penalties to be assessed for 60 days after the notice of expiration is sent to the customer. This proposed amendment would also define some examples of fraudulent activities such as using the term "fixed" when the product does not meet the definition of a fixed-price product.

The proposed rules were published in August 2008, with a request that interested persons file comments. The Commission will consider and respond to the comments filed by members of the public. It expects to consider adopting the new rules by early 2009.

3. Provider of Last Resort

The Commission has proposed amendments to the rule relating to the provider of last resort (POLR) and published the proposed amendment for public comment.[15] The amended rule will address the market and operational processes for POLRs, including: structure and pricing, notification to customers, and reporting requirements. The proposed rule replaces the term POLR with Emergency Service. The proposed rule includes a three-tier structure, consisting of Volunteer Emergency Service Providers, Mandatory Emergency Service Providers, and POLRs.

The expectation is in the event that a small REP leaves the market under circumstances in which new service providers must supply service to the REP's customers, the customers would be transferred to Volunteer Emergency Service Providers and Mandatory Emergency Service Providers at a competitive rate. If a large REP leaves the market, the customers would be transferred to POLRs and would be served at a rate based on the prices in the ERCOT balancing energy market.

Under the proposed rule, a post-card notification will be sent to customers who are being transferred to an emergency service provider or POLR. ERCOT would be responsible for mailing the postcard on behalf of the Commission. In addition, all REPs would be required to submit accurate customer data to ERCOT on a monthly basis. This information would include the electric service identification number, service address, phone number, email address, and customer name. The purpose of the information is to provide an emergency service provider or POLR better information on the customers it is acquiring. A REP would be subject to enforcement action for failure to provide a report or failure to provide accurate information.

The proposed rule was published in November 2008, and the Commission expects to analyze the comments that are submitted and adopt amendments to the rule in early 2009.

[15] *Rulemaking Relating to Provider of Last Resort*, Project No. 35769, proposing amendments to P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR) (pending).

e. Performance Measures

The Commission requires ERCOT, REPs, and transmission and distribution utilities (TDUs) in the competitive market to file quarterly performance measures that report their performance on key tasks. The Commission modified the retail performance measures to implement new standards for TDUs' field performance under the standardized Retail Delivery Tariff.[16] The standardized tariff provides deadlines for the timely completion of customer switches from one REP to another, move-ins or move-outs requested by customers, and the disconnection of customers for non-payment and subsequent reconnection upon receipt of payment by the REP. The tariff requires that all reconnections after a disconnection for non-payment be completed the same business day if the service order is received before 2:00 p.m., the next business day if received after 2:00 p.m., and within 48 hours under all circumstances, including holidays and weekends. The new performance measures implement a requirement of 98 percent on-time completion for move-ins, and switches, as well as same day reconnection when the service order is received before 2:00 p.m. Any failure to meet these standards requires explanation, correction and, when necessary, may result in penalties for continued substandard performance.

A new filing package for performance measures also adds measures to monitor the performance of the ERCOT-based computer systems needed to transact business in the retail and wholesale markets, and the frequency and resolution of situations where a customer may have been moved from one REP to another without authorization.

2. Major Wholesale Market Rulemakings

a. Emergency Demand-Response Programs

In response to an electric system event that resulted in interruption of some customers' electric service on April 17, 2006, the Commission adopted a rule in March of 2007 to establish an emergency demand-response program that would permit ERCOT to deploy voluntary load reductions in an emergency event that might result in an interruption in electrical service.[17] The rule allowed ERCOT to contract with demand-response providers for up to 1,000 MW of emergency interruptible load (EILS) to be deployed during an emergency event declared by ERCOT. ERCOT may contract up to three times per year for voluntary customer interruptions. The rule also established a cost cap for the program of $20 million per year.

Initially, ERCOT was unable to obtain sufficient interest from customers willing to provide voluntary interruptions. Potential participants in the program believed that there

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[16] *Proceeding to Amend Form for Commission Subst. R. §25.88, Retail Market Performance Measures Reporting*, Docket No. 33049; the Retail Delivery Tariff is in P.U.C. SUBST. R. 25.214 (Dec. 13, 2007).

[17] *Rulemaking Concerning a Demand-Response Program for ERCOT Emergency Conditions*, Project No. 33457 (Mar. 21, 2007).

was too much uncertainty in the program for them to put the necessary controls into place to participate. Therefore, the Commission amended the rule in November of 2007 to alleviate some uncertainties in the program.[18] The new rule eliminated a 500 MW minimum procurement requirement, and raised the cost cap to $50 million per year. The rule allowed ERCOT flexibility in deciding when the service was needed. The rule also clarified that ERCOT is not required to accept a bid it determines to be unreasonable. Following the Commission's adoption of these amendments, ERCOT was successful in obtaining customers willing to provide voluntary interruptions with contracts up to 300 megawatts of EILS. Most recently, ERCOT procured an average of 290 MW per hour during business hours for October 2008 through Jan 2009 at a projected cost of $8,268,000. Projected costs for the EILS program from February 2008 to January 2009 total $19,966,000.

b. 500 MW Non-Wind Renewable Portfolio Standard

To encourage the diversification of renewable energy in Texas, in July of 2007 the Commission adopted an amendment to its rule relating to the goal for renewable energy.[19] The amendment increased the state's renewable portfolio standard (RPS) and established a target of 500 MW of capacity from a renewable energy technology other than wind energy by 2015. Both rule changes were required by Senate Bill 20, enacted in 2005, which amended PURA §39.904, relating to the Goal for Renewable Energy. The 80th Legislature adopted House Bill 1090, which further amended PURA §39.904 authorizing the Commission to establish a separate alternative compliance payment for the non-wind target.

Under the amended rule, non-wind renewable energy facilities that began operating after September 1, 2005, are granted both a renewable energy credit (REC) and a compliance premium for each MWh generated after December 31, 2007. A compliance premium may be used by an entity towards its RPS requirement, and the statewide RPS requirement calculated for each compliance period will be increased by the number of compliance premiums retired during the previous compliance period. While some stakeholders expressed concern about the effectiveness of compliance premiums as an incentive for the development of non-wind renewable resources, the new rule contains several other amendments intended to provide additional incentives for non-wind resources. In particular, the rule permits fossil fuel generating facilities that switch to a renewable fuel source the right to earn RECs and allows small renewable resources to aggregate their energy for purposes of earning RECs. At the time, the Commission believed there was significant uncertainty regarding its authority to create a separate RPS for non-wind renewable resources.

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[18] *Rulemaking to Amend ERCOT Emergency Interruptible Load Service*, Project No. 34706 (Nov. 8, 2007).

[19] *Rulemaking Relating to the Target for Renewable Resources Other Than Wind Power*, Project No. 33492 (Aug. 6, 2007).

In June 2008, the Commission initiated a project to further review rules relating to the 500 MW non-wind target.[20] The Commission solicited comments on whether additional measures are necessary or appropriate and which measures would be most cost-effective in providing inducement for the development of additional non-wind renewable generation. The request for comments also sought input on the issue of the Commission's authority to create a separate REC requirement for non-wind renewable resources.

3. Other Rulemakings

a. *Transmission Providers for CREZ Development*

Senate Bill 20 passed by the 79th Legislature requires the Commission to develop a transmission plan to deliver the output of the renewable energy zones in a manner that is most beneficial and cost-effective to customers. In May 2008, the Commission adopted a new rule for the selection of transmission service providers (TSPs) for the transmission facilities that will be built for the Competitive Renewable Energy Zones (CREZs).[21]

Under the new rule, companies interested in building and operating the transmission facilities needed for the CREZs may submit an application to the Commission. The Commission determined a company does not have to be an existing utility in Texas to apply to build and operate CREZ facilities.[22] In its selection of TSPs, the Commission must favor those who can provide the most beneficial and cost-effective plan to customers. The evaluation factors the Commission will consider include:

- Applicants' capabilities to finance, license, construct, operate, and maintain the CREZ facilities;
- Expertise of applicants' staff;
- The projected capital costs and operating and maintenance costs for the facilities;
- The proposed schedule for development and completion of facilities;
- The expected use of historically underutilized businesses; and
- Applicants' previous transmission experience and historical operating and maintenance costs for transmission facilities.

The Commission held a hearing in December 2008 for selecting the TSPs and expects to make a decision in January 2009.

[20] *Rulemaking Relating to the Goal of Renewable Energy*, Project No. 35792, adopting P.U.C. SUBST. R. 25.216, Selection of Transmission Service Providers (pending).

[21] *Rulemaking Proceeding to Amend PUC Substantive Rules Relating to Selection of Transmission Service Providers for Competitive Renewable Energy Zones and Other Special Projects*, Project No. 34560, adopting P.U.C. SUBST. R.. 25.216, Selection of Transmission Service Providers (Jun. 19, 2008).

[22] Companies awarded CREZ projects must become certificated utilities before constructing transmission facilities.

b. Nuclear Decommissioning Costs

The 80th Legislature passed HB 1386, which added § 39.206 to PURA, requiring power generation companies (PGCs) to establish a nuclear decommissioning trust for nuclear generation capacity they own. The Commission adopted a new rule in February 2008 that establishes the minimum financial assurance standards for competitive PGCs constructing nuclear generation power plants as well as the funding, administration, and monitoring requirements for nuclear decommissioning trust funds.[23]

The financial assurance standards of the rule permit a PGC that owns all or a portion of a qualifying nuclear generating unit to establish a PGC decommissioning trust as an external sinking fund. If a PGC elects to use a PGC decommissioning trust, the PGC must apply for a Commission order establishing the amount of annual decommissioning funding and approving the trust agreements. The rule also requires that a PGC that uses a Commission-approved PGC decommissioning trust must provide additional financial assurances that funds will be available to satisfy 16 years of annual decommissioning funding, based on the most recent annual decommissioning funding amount approved by the Commission. Under the rule, if the PGC fails to meet its annual funding requirements the Commission shall determine the manner in which any shortfall in the cost of decommissioning a nuclear generating unit may be recovered from retail electric customers in the state.

The rule also requires annual reports on the status of the PGC's decommissioning trusts, any changes in the administration of the trusts, and an update of its ability to fund the trusts. Similar to the Commission's decommissioning rules for regulated utilities, the new rule requires that the PGC decommissioning trust be managed so that funds are secure and earn a reasonable return, and that funds provided from the PGC's operating revenues, plus the amounts earned from investment of the funds, are available at the time of decommissioning. The rule further requires specific safeguards be in place for the trust investments.

c. Emergency Plans for Electric Utilities

On January 4, 2008, the Commission adopted a new rule relating to electric service emergency operations plans, which applies to ERCOT, electric utilities, TDUs, REPs, PGCs, and electric cooperatives (collectively referred to as "electric companies").[24] Each electric company was required to file a copy of its emergency operations plan or summary by May 1, 2008, with updates as necessary. TDUs and electric cooperatives are required to include the following items in their filing with the Commission:

1. How they register critical load customers;

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[23] *Rulemaking to Nuclear Decommissioning Costs*, Project No. 34888, adopting P.U.C. SUBST. R. 25.304, Nuclear Decommissioning Funding and Requirements for Power Generation Companies (Feb. 28, 2008).

[24] *Rulemaking to Repeal P.U.C. Substantive Rule 25.53 and Propose New 25.53 Relating to Electric Service Emergency Operations Plans*, Project No. 34202 (Jan. 4, 2008).

2. A communications plan for contacting the media, customers, and critical load customers;
3. Curtailment priorities, procedures for shedding load, rotating black-outs, and planned interruptions;
4. Priorities for restoration of service;
5. A pandemic plan or summary; and
6. A hurricane plan or summary.

Electric utilities and PGCs are required to include the following items in their filing with the Commission:

1. A summary of power plant weatherization plans;
2. A summary of alternative fuel and storage capacity;
3. Priorities for recovery of generation capacity;
4. A pandemic preparedness plan or summary; and
5. A hurricane plan or summary.

ERCOT and REPs are required to file an affidavit attesting that they have a business continuity plan and pandemic plan. Other requirements applied to all market entities include conducting an annual drill if their emergency operations plan is not implemented due to a natural or manmade disaster. They are also required to supply the Commission with emergency contact information, which is to be updated as necessary. During an emergency event such as a hurricane, these individuals are contacted by the Commission to obtain outage and restoration information. This information is then forwarded to the Governor's Division of Emergency Management to generate situation reports that are reviewed by the Governor's Office, state agencies, and local jurisdictions.

B. Contested Proceedings

1. TCC Rate Case

On November 9, 2006, American Electric Power Texas Central Company (AEP TCC) filed a request to increase its revenues for electric delivery service by $62.7 million, an increase of 13.0 percent. In the course of the proceeding, AEP TCC reduced its request to $50 million. In addition, AEP TCC proposed the elimination of merger savings and rate reduction riders related to the merger of American Electric Power, Inc. and Central and South West Corporation, which would increase distribution revenues by $20 million. The combined effect of these requests was an overall 17.2 percent increase in TCC's revenues.

Following the hearing, the Commission approved an increase in revenue that was $40 million less than AEP TCC's original request.[25] In making its determination, the Commission included a return on the equity invested in AEP TCC of 9.96 percent, a cost

[25] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309 (Mar. 4, 2008).

of debt of 5.86 percent, and a capital structure of 60 percent debt and 40 percent equity, resulting in a weighted average cost of capital of 7.499 percent.

2. TNC Rate Case

On November 9, 2006, American Electric Power Texas North Company (AEP TNC) filed an application for authority to change rates for electric delivery service, requesting an increase in revenues of $18.8 million for its transmission and distribution operations and to terminate $6.2 million in credit riders that were adopted as a part of the Central and South West/AEP merger proceeding. Combined, these amounts resulted in a total revenue increase of $25 million. In the course of the proceeding, AEP TNC reduced this amount by $200,000.

On May 11, 2007, following the hearing, AEP TNC filed a Stipulation and Agreement among all of the parties that actively participated in the proceeding. The Agreement provided for an overall increase in revenues of $13.7 million, composed of a $7.5 million increase in base rates and discretionary fees, and $6.2 million from the termination of the credit riders. The Agreement also provided that the return on equity approved by the Commission for AEP TCC in Docket No. 33309 would be used for AEP TNC for any purpose that requires a return on equity, and that AEP TNC's weighted average cost of capital would reflect a capital structure consisting of 60 percent debt and 40 percent equity. [26]

3. Entergy Rate Case

On September 26, 2007, Entergy Gulf States initiated a rate case with the Commission to increase rates by about $50 million, including a 15 percent increase to residential rates. Other rate classes, including Large Industrial Power Service, would have received a decrease in rates under the application. In January 2008, Entergy completed its jurisdictional separation plan, dividing Entergy Gulf States into two subsidiaries, Entergy Louisiana, serving its customers in Louisiana, and Entergy Texas, serving the Texas portion of its service area.

Entergy reached a non-unanimous settlement with some of the parties to the case, including the Office of Public Utility Counsel, that would allow Entergy to receive approximately all of its request, but which would reallocate the revenue requirement among the customer classes so that all classes' rates, including residential, would increase by about eight percent. Commission Staff, the Texas Industrial Energy Consumers, and the State of Texas agreed to a second non-unanimous settlement that would result in the Entergy rates staying very nearly the same as prior to this rate case. Following the issuance of a proposal for decision by judges of the State Office of Administrative Hearings (SOAH) accepting the Entergy NUS, the Commission rejected the NUS for

[26] *Application of AEP Texas North Company for Authority to Change Rates,* Docket No. 33310 (May 29, 2007).

failing to meet the standards for approval of a NUS and remanded the case to SOAH for a hearing on the original application.[27]

4. LCRA Transmission Rate Case

On November 15, 2007, LCRA Transmission Services Corporation (LCRA TSC) filed a request to increase its wholesale transmission rates. An unopposed stipulation reached between LCRA TSC and Commission Staff was approved by the Commission on June 11, 2008.[28] Since the previous transmission rate was approved, LCRA TSC's capital investment has grown 11 percent to $1.15 billion.

5. RPRS Protocol Appeal

In its function as system operator, ERCOT is responsible for maintaining the security and reliability of the electric transmission system. If ERCOT determines on a day-ahead basis that the expected generation of electricity is not sufficient to meet the forecasted load, it may purchase Replacement Reserve Service (RPRS), which is additional generation capacity that can be used to ensure that there is no interruption of electric service. Shortly after ERCOT began using the RPRS service in March 2006, it became apparent that the cost allocation for this service – which assigned a significant portion of the RPRS costs to market participants who were deemed to be "short scheduled" – was having unexpected results. A market participant is deemed to be short scheduled when its actual generation is less than its stated generation target. After consideration of various proposals, the ERCOT Board adopted Protocol Revision Request (PRR) 676 to clarify how the costs would be allocated. A market participant appealed PRR 676 to the Commission, charging that the allocation was not based on cost causation and that it violated certain provisions of PURA and the Commission's rules. The Commission held a hearing on the merits, and in April 2007 it adopted an order that reversed the approval of PRR 676 and directed that the costs of RPRS to be charged to all market participants on a load ratio share basis, that is, on the basis of each market participant's load compared to the total system load.[29]

6. Entergy Securitization of Storm Costs

On July 5, 2006, Entergy Gulf States Inc. (EGSI) filed an application under PURA §§ 39.458-.463 to securitize Hurricane Rita storm costs. Enacted in 2006, House Bill 163 enables an electric utility subject to PURA Chapter 39, Subchapter J (namely, EGSI) to obtain timely recovery of hurricane reconstruction costs and to use securitization financing to recover these costs. This type of financing lowers the carrying costs

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[27] *Application of Entergy Gulf States, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 34800 (Nov. 5, 2008).

[28] *Application of LCRA Transmission Services Corporation to Change Rates*, Docket No. 35020 (Jun. 11, 2008).

[29] *Constellation NewEnergy, Inc's Appeal and Complaint of ERCOT Decision to Approve PRR 676, PRR 674 and Request for Expedited Relief*, Docket No. 33416 (Apr. 13, 2007).

associated with the recovery of hurricane reconstruction costs relative to the costs that would be incurred using conventional financing methods.

On November 17, 2006, parties to the proceeding filed a settlement agreement, which provided that the total dollar amount eligible to be securitized would be $381 million, plus carrying costs and other qualified costs, and less an estimated amount of $65.7 million related to insurance payments expected to be made to EGSI. On December 1, 2006, the Commission approved the settlement.[30] Shortly thereafter, on December 8, 2006, EGSI filed its application for a financing order to securitize the settlement amount. The Commission issued its financing order on April 2, 2007,[31] approving the securitization requested by EGSI and authorizing the issuance of transition bonds in an aggregate principal amount not to exceed the sum of (a) $321 million of hurricane reconstruction costs, plus (b) up-front qualified issuance costs not to exceed $6,000,000, minus (c) governmental grant proceeds received prior to the issuance of the financing order. On June 29, 2007, pursuant to the terms of the financing order and including a carrying-cost adjustment of approximately $2.5 million, EGSI issued securitized bonds in the amount of $329.5 million.

7. AEP Mid-American Sale of Assets

In January 2007, Electric Transmission Texas (ETT) filed an application for a Certificate of Convenience and Necessity (CCN), in order to transfer transmission assets from AEP Texas Central (AEP TCC) to ETT. ETT also sought approval of rates, as a transmission utility. ETT is 50 percent owned by AEP Texas Central and 50-percent owned by MidAmerican Energy Holdings Company (MidAmerican), a subsidiary of Berkshire Hathaway, Inc. ETT also requested waiver of certain affiliate rules that would be difficult and onerous to comply with given the affiliate status of Berkshire Hathaway and all of its many subsidiary companies.

The Federal Energy Regulatory Commission, in answer to questions about jurisdiction over this transfer, disclaimed jurisdiction. Several parties opposed the granting of the CCN, arguing that ETT, as a transmission-only company, lacked a service area and was therefore ineligible for a CCN. Opponents also argued that the Commission should not approve transmission rates, as ETT was not completely formed and had not yet invested in any facilities other than those being transferred to it by AEP TCC.

The Commission granted the CCN, concluding that the creation of ETT was in the public interest. It also approved transmission rates for ETT and a negotiated code of conduct for ETT.[32] Several parties that opposed the issuance of the CCN filed petitions for judicial review in the District Court of Travis County. On October 8th, 2008, the

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[30] *Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs*, Docket No. 32907 (Dec. 1, 2006).

[31] *Application of Entergy Gulf States, Inc. for a Financing Order*, Docket No. 33586 (Dec. 12, 2006).

[32] *Application of Electric Transmission Texas, LLC for a Certificate of Convenience and Necessity, for Regulatory Approvals and for Initial Rates*, Docket No. 33734 (Dec 2007).

District Court issued an order reversing the Commission's decision, concluding that the Commission did not have the authority to create such a new utility. The Commission has filed a motion to revise the order.

8. TXU Power Generation Company

In the fall of 2006, Commission Staff requested that an investigation of TXU's market activities during the summer of 2005 be conducted by Potomac Economics, which serves as the Commission's Independent Market Monitor (IMM) for ERCOT wholesale electricity market. Potomac Economics evaluated market activities during the period 10:00 a.m. through 11:00 p.m. from June 1, 2005 through September 30, 2005 (the study period) and concluded that TXU had the ability to substantially increase balancing energy prices, because its energy offers were necessary to satisfy the demand in the ERCOT balancing energy market. The IMM also concluded that TXU abused its position by offering its energy into the market at prices well in excess of its marginal cost. According to the IMM report, TXU knew that it had the ability to substantially increase balancing energy prices and it could foresee that withholding significant quantities of energy would likely result in higher market prices. The IMM report states:

> *When TXU offers its capacity at well above short run marginal costs, TXU expects that its offer strategy will raise the MCPE enough to compensate it for any foregone sales. Given the frequency with which TXU is pivotal, and the historical information available to TXU on offer patterns and deployments in the balancing energy market, this is a reasonable expectation because TXU could foresee that economically withholding significant quantities would be likely to result in higher balancing market prices.*[33]

The IMM therefore concluded that TXU's actions constituted an abuse of market power in the balancing energy market.

Potomac Economics initially estimated that the direct cost to the balancing energy market due to TXU's economic withholding of production amounted to approximately $70 million.[34] On March 28, 2007 the Executive Director of the Commission issued a Notice of Violation, to TXU, with a proposed penalty equal to three times the harm to the market, or $210 million.[35]

In the spring of 2007 the TXU companies that were the subject of the Commission investigation were acquired by Energy Future Holdings Corp. and were renamed the Luminant companies. In the summer of 2007, Potomac Economics discovered an error in the ERCOT data used to calculate the harm to the market due to the Luminant parties' activities, and adjusted its estimate of the harm to the market to $57 million. Subsequently, Commission Staff amended its penalty recommendation and, in a revised

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[33] Revised Investigation of the Wholesale Market Activities of TXU from June 1 to September 30, 2005, Potomac Economics, p 23; September 2007.

[34] Ibid. p 31.

[35] *Notice of Violation of TXU Corp., et al. of PURA § 39.157(a) and P.U.C. SUBST. R. 25.503(g)(7),* Docket No. 34061 (Dec. 22, 2008).

Notice of Violation issued on September 14, 2007, recommended penalty of $171 million. On November 26, 2008, the Commission Staff and Luminant filed a settlement in the case. The Commission approved this settlement on December 18, and Luminant has paid a $15 million administrative penalty to resolve these issues.

9. TEF Acquisition of TXU Corporation

In April 2007, Texas Energy Future Holdings Limited Partnership (TEF) and Oncor Electric Delivery Company filed a request for a Commission determination that the merger of TEF and Oncor's parent, TXU Corp. was consistent with the public interest under PURA § 14.101(b). The Commission concluded that it could enforce the commitments made by TEF that are directly related to the public utility and approved the request for a public interest finding, following the submission of a non-unanimous stipulation of many of the parties to the proceeding.[36] The applicants and parties agreed to 53 commitments addressing governance, financial conditions, service quality, energy efficiency, and transaction costs. They also agreed to a $72 million credit to retail electric providers that they passed on to their customers.

While the merger was pending, the Legislature enacted House Bill 624, which requires preapproval by the PUC of any merger involving a transmission and distribution utility or any transaction in which more than 50 percent of the stock of a utility holding company changes ownership. HB 624 did not apply to agreements reached prior to April 1, 2007, such as the merger of TXU Corporation with TEF. The Commission reviewed the merger under prior law, which permitted the Commission to determine whether a merger was in the public interest.

On October 10, 2007, the merger was consummated and TEF became the owner of all or substantially all of the outstanding shares of TXU Corp.

10. CREZ

In December 2006, Commission Staff initiated the CREZ proceeding, and ERCOT filed a study identifying the areas in Texas with the best wind energy resources as well as an estimation of the cost of transmission required to bring energy from those areas into the major load centers in central Texas. In the first phase of the proceeding, wind energy developers provided evidence of the areas in which they had made investment in wind, such as signing leases or installing wind turbines. Based on the ERCOT report and the evidence from developers and other parties, the Commission issued an order, in October 2007, directing ERCOT to study four different scenarios for the development of wind energy and report its findings to the Commission. The order identified areas in West Texas for further study and set out levels of development that ranged from 12,000 megawatts of wind capacity to over 24,000 megawatts. The development scenarios that the Commission directed ERCOT to study are summarized in the following figure.

[36] *Joint Report and Application of Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership Pursuant to PURA § 14.101*, Docket No. 34077 (Apr. 24, 2008).

Table 1: CREZ Development Scenarios

Capacity of CREZ Wind Development by Scenario (megawatts)				
Wind Zone	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Panhandle A	1,422	3,191	4,960	6,660
Panhandle B	1,067	2,393	3,720	0
McCamey	829	1,859	2,890	3,190
Central	1,358	3,047	4,735	5,615
Central West	474	1,063	1,651	2,051
Total*	12,053	18,456	24,859	24,419
*Assumes 6903 megawatts of existing wind capacity				

In April 2008, ERCOT filed the study of these scenarios and a separate study of the requirements for maintaining system reliability with large amounts of wind generation. The study required by the Commission, called the CREZ Transmission Optimization Study,[37] provided a conceptual design for the new transmission facilities that would be required for each wind development scenario. Based on these studies and additional evidence from the parties, the Commission selected Scenario 2 and, in August 2008, issued an order designating competitive renewable energy zones, a level of wind development in each CREZ, and the transmission improvements necessary to deliver the wind capacity to customers.[38]

The Commission designated five areas as CREZs, two areas in the Panhandle, two in Central and West Central Texas, extending west from the Abilene area, and one in the McCamey area. It also identified the major transmission improvements necessary to deliver renewable resources of 18,456 MW to customers. The estimated cost for major transmission improvements to support the development of this level of wind generation from the CREZs is $4.93 billion. The transmission improvements include 2,334 miles of new 345-kilovolt right-of-way, and 42 miles of new 138-kilovolt right-of-way. The CREZs and the conceptual routing of the new transmission facilities are shown in the following figure. The actual routing will be developed in subsequent CCN application proceedings.

One of the issues that the Commission considered in the CREZ proceeding was the impact of significant levels of additional wind capacity on reliability and the possibility that additional costs will be incurred in a high-wind environment to maintain reliability. In the CREZ proceeding, the Commission concluded, based on a study

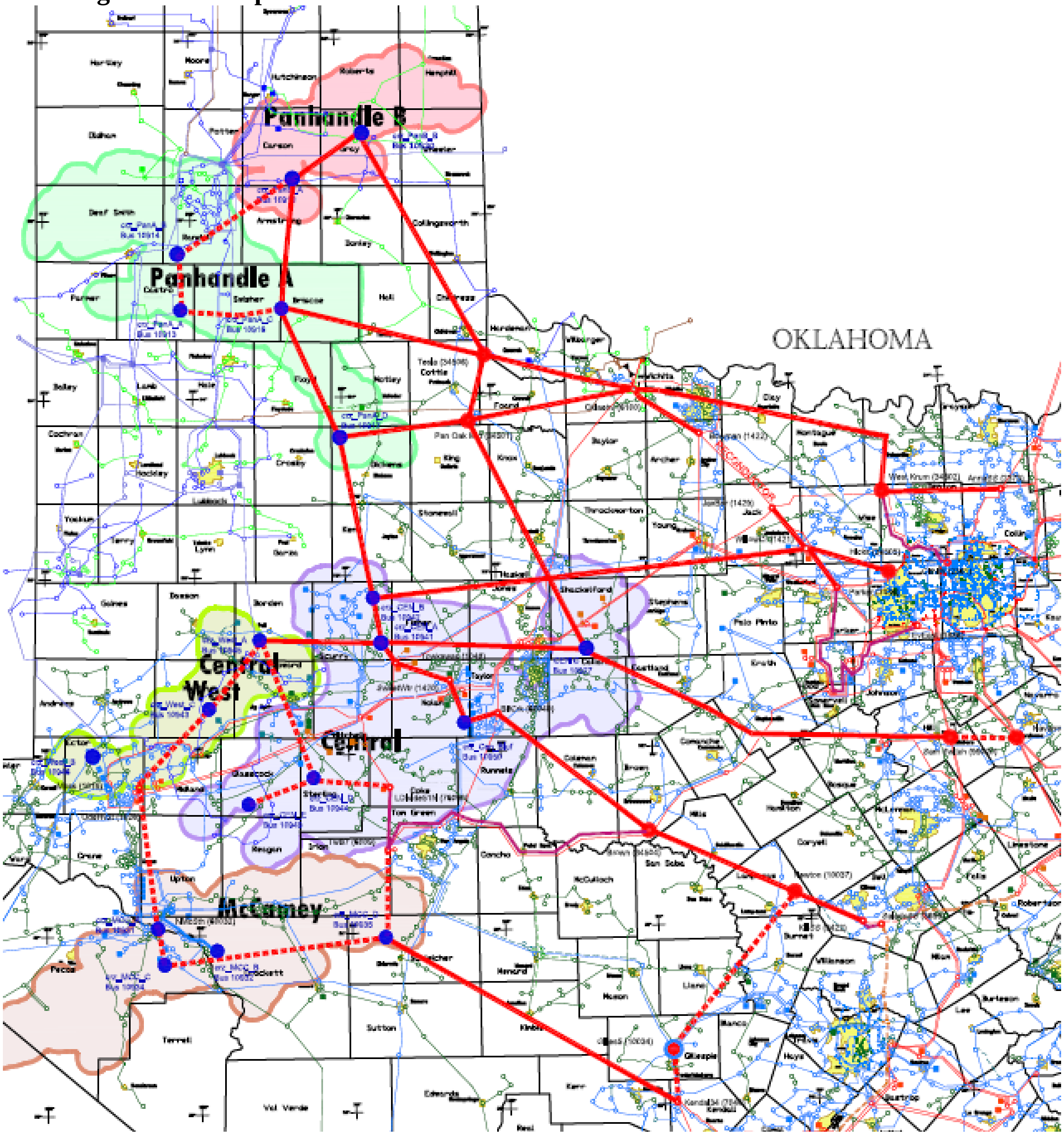
[37] *See* www.ercot.com.

[38] *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*, Docket No. 33672 (Oct. 7, 2008).

presented by General Electric International, Inc. (GE), that the displacement of thermal units with wind generation reduces the overall spot price of energy.[39] The GE study concluded that, although the total regulation service procured in a year would increase with increased wind generation capacity, increased wind capacity tends to reduce the per-MWh price, resulting in a small cost of regulation per MWh of wind generation. In addition, the study evaluated reserve services, and made the analogy that rapid drops in wind generation output are much like a rapid increase in load. The study suggested ways to influence and manage the relative costs of increased wind penetration on the reserve services, such as the development of an additional reserve services, more certain wind forecasting, and higher confidence levels for commitment schedules. The Commission did not adopt an explicit estimate of the costs of ancillary services to maintain reliability in a high-wind scenario, but it is confident that system and market adjustments can be made that will result in maintaining reliability and reducing overall system costs with the wind development scenario it approved.

[39] GE's Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, ERCOT Resource 3 at RW-2, Executive Summary at 8, and at 5-9.

Figure 1: Competitive Transmission Zones and CREZ Transmission Plan



11. Selection of CREZ Transmission Providers

In May 2008, Commission Staff filed a petition to commence a proceeding for the selection of entities responsible for transmission improvements necessary to deliver renewable energy from the CREZ.[40] A procedural schedule was adopted and the Commission held a hearing in early December. Many Texas transmission providers and other foreign and domestic companies expressed interest in being a CREZ transmission provider. Twelve entities submitted applications to build and operate CREZ facilities, including four companies that are not currently transmission providers in Texas. After the transmission service providers are selected, they will develop and file applications for CCNs for the transmission projects identified by the Commission in the CREZ proceeding. These CCN applications will be processed by the Commission on a six-month timeline. After approval by the Commission, the right-of-way acquisition, design, material procurement, and construction will take two to three years, depending upon the length and route of each line. The CREZ transmission lines are expected to be energized in 2012 and 2013. A decision by the Commission is expected in early 2009.

12. Oncor AMS Deployment

In May 2008, Oncor Electric Delivery Company filed a plan with the Commission for full advanced-meter deployment in its service territory.[41] Oncor intends to deploy approximately 3.4 million advanced meters over the next four years with advanced metering infrastructure that meets the requirements of the Commission's advanced metering rule. Settlement among the parties was reached in this case and was approved by the Commission on August 28, 2008. Oncor was authorized to implement a surcharge to support the effort over an eleven-year period beginning in January 2009. Residential customers will pay a surcharge of $2.21 per month, beginning in January 2009.

The estimated capital cost of the Oncor AMI deployment is $686 million and the estimated operating and maintenance costs are $153 million during the surcharge period. The Oncor plan includes an estimated total cost savings of $176 million for meter reading services, and $28 million of ad valorem tax savings related to the existing meters that will be replaced by the advanced meters. This cost savings is reflected in the customer surcharge.

Educating consumers about the actions they need to take to realize the benefits of advanced metering is an important element of a successful advanced meter deployment. Oncor's advanced meter deployment includes a $15 million comprehensive customer education program called "SMART TEXAS - *rethinking energy*" that will educate retail electric customers about the benefits that can be achieved through the use of an advanced meter. Oncor's plan includes a Mobile Experience Center (a hands-on educational tool that will travel throughout Oncor's service territory in advance of the deployment), educational door hangers, and newspaper, billboard and movie theater advertisements.

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[40] *Commission Staff's Petition for the Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable Energy Zones*, Docket No. 35665 (pending).

[41] *Oncor Electric Delivery Company LLC's Request for Approval of AMS Deployment Plan*, Docket No. 35718 (Aug. 29, 2008).

To ensure that low-income customers are able to receive the benefits of advanced meters, the Oncor plan includes a $10 million low-income program. This program will work with the appropriate state and local agencies to coordinate the distribution of in-home consumption monitors to low-income customers in Oncor's service area. These devices communicate with the Oncor advanced meters, giving low-income customers convenient, real-time access to their energy usage information and allowing them to take actions to better control their energy usage and reduce monthly electric bills.

13. CenterPoint Energy AMS Deployment

CenterPoint Energy Houston Electric (CenterPoint) filed two separate but complementary plans with the Commission for AMI deployment. The first plan is a request to allow REPs to fund the deployment of AMI.[42] The Commission approved a settlement in this docket on August 28, 2008. This deployment plan will allow a total of 127,000 advanced meters to be deployed in the CenterPoint territory on an expedited basis. Under the plan, REPs may finance the build-out of advanced meters and the related infrastructure before CenterPoint implements deployment across its service territory. Such accelerated deployment is consistent with "the intent of the legislature that net metering and advanced meter information networks be deployed as rapidly as possible to allow customers to better manage energy use and control costs, and to facilitate demand-response initiatives."[43]

The second plan filed by CenterPoint is for a limited deployment.[44] An unopposed settlement among the parties was filed in December and was approved by the Commission on December 18th. Centerpoint will deploy approximately 2.1 million meters over the next five years, with an AMI that meets the requirements of the Commission's advanced metering rule. CenterPoint's surcharge covers a twelve year period, beginning in February 2009. The settlement also included funding for customer education and in-home devices for low income customers. Residential customers will pay $3.24 per month for the first 24 months and the surcharge will decrease to $3.05 for the remainder of the surcharge period.

The estimated capital cost of the CenterPoint AMI deployment is $639.6 million and the estimated operating and maintenance costs are $207.9 million during the surcharge period. The CenterPoint deployment plan includes an estimated total cost savings of $120.6 million. This cost savings is reflected in the customer surcharge. Because customer education is a critical component of AMI deployment, CNP has included $5.6 million for customer education. CenterPoint has also included $7.5 million to fund a low-income program to help those customers receive the benefits of advanced meters. Similar to the Oncor program mentioned above, the program will work with the

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[42] *Application of CenterPoint Energy Houston Electric, LLC for Approval to Implement Advanced Meter Information Network*, Docket No. 35620 (Aug. 29, 2008).

[43] PURA § 39.107(i).

[44] *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System*, Docket No. 35639 (Dec. 28, 2008).

appropriate state and local agencies to coordinate the distribution of in-home consumption monitors to low-income customers in CenterPoint's service area.

In early 2007, CenterPoint opened its Technology Center in Houston. This Technology Center demonstrates the company's vision for AMI and its future smart grid. The center includes a display that features the advanced metering system and the other functions it can perform. CenterPoint has given over 300 tours to the public, Commission staff, and policy makers from local, regional and national levels, as well as utilities from around the world.

14. CenterPoint Securitization

On December 17, 2004, the Commission issued an Order on Rehearing in Docket No. 29526 determining that CenterPoint was entitled pursuant to PURA § 39.262 to recover $2,300,888,665 of true-up costs associated with the transition to a competitive retail market. After the Commission's subsequent issuance of the financing order in Docket No. 30485 for the securitization of the stranded-cost portion of the total recoverable balance, CenterPoint securitized approximately $1.8 billion of its true-up costs via transition bonds issued December 16, 2005. Following the language in PURA, the Commission determined that a portion of the true-up balance was not eligible for securitization, the remainder of the costs continued to be recovered through competition transition charges pursuant to the Commission's order in Docket No. 30706. Subsequently, during the 2007 legislative session, the legislature amended PURA to permit securitization of the entire true-up balance.[45]

On June 28, 2007, CenterPoint filed its application for a financing order under Subchapter G of Chapter 39 of PURA to permit securitization of its remaining true-up balance plus up-front qualified costs. In July 2007, CenterPoint submitted an unopposed settlement agreement that the Commission approved, with certain modifications, at its open meeting on August 16, 2007. The Commission issued its financing order in September 2007 and, in February 2008, CenterPoint completed the issuance of the securitized bonds in the amount of $488 million.

C. Competitive Market Oversight Activities

In September 2007, the Commission underwent a reorganization of its oversight responsibilities. A new Competitive Markets Division (CMD) was created and the Electric Industry Oversight Division (EIO) was eliminated. Most of the staff in the Wholesale Market Oversight and Retail Market Oversight sections of EIO were transferred to the new CMD. New Wholesale and Retail Market sections in CMD are now responsible for evaluating market design issues and analyzing the competitiveness and effectiveness of the market. A new Oversight and Enforcement Division has been created that is responsible for all aspects of compliance with and enforcement of Commission rules.

[45] Act of May 30, 2007, 80th Leg., R.S., H.B. No. 624 § 2-4 (to be codified as an amendment of the Public Utility Regulatory Act § 39.301-.303).

1. Retail Market Oversight

The Commission's Competitive Markets Division is divided into two sections: Retail Markets and Wholesale Markets. The Retail Markets section performs oversight of the retail electric market 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;
- Representing the public interest in contested cases, formal complaints and rulemaking proceedings;
- Ongoing review of appropriateness and completeness of Commission rules governing the operation of the retail market, including customer protections; and
- Monitoring retail market issues, participating in ERCOT stakeholder discussion of retail issues, working to find solutions to retail market issues and analyzing trends in the retail market

Retail Market Staff also communicate with retail electric providers and ERCOT in connection with significant retail market events, such as the exit of retail electric providers from the market, in circumstances in which customers may be transferred to a provider of last resort. The staff's objective in these events is to see that the transfers occur efficiently, and that customers' rights under Commission rules are observed.

2. Wholesale Market Oversight

The Commission's wholesale market oversight activities, with respect to the ERCOT market, are supported by the Independent Market Monitor (IMM). In accordance with statute, the IMM is selected by the Commission, but funded by ERCOT.[46] The consulting firm Potomac Economics serves as the IMM. Potomac analyzes the market by using computer programs that permit it to organize and analyze large amounts of market data. The IMM provides reports to the Commission on a daily basis, special reports as required by market events, and an annual report. The Commission publishes the IMM's annual report on its web page, and uses its daily reports in an interactive reporting section on the web page relating to prices and congestion in the wholesale market.[47] The IMM's reports may identify areas requiring further investigation or enforcement activities, and it has participated in enforcement investigations. The oversight activities relating to wholesale market design include:

- Review of the operations of the market, as measured through the analysis of ERCOT wholesale market data, IMM reports, and other competitive market indicators;

[46] PURA § 39.1515, Tex. Util. Code § 39.1515.

[47] Annual reports are available at www.puc.state.tx.us/wmo/documents/index.cfm, and the interactive reporting is at www.puc.state.tx.us/wmo/index.cfm.

- Review of Commission rules and the ERCOT Protocols governing the operation of the wholesale market in order to identify opportunities for improving the efficiency of the market; and
- Analysis of ERCOT and its role in the operation of the wholesale market.

Commission staff participates in ERCOT stakeholder meetings on a routine basis to monitor discussions of design issues and contribute to the development of design decisions that are supportive of vibrant wholesale competition. Similarly, the Commissioners participate in meetings of the ERCOT board of directors, and the Chairman of the Commission is a non-voting member of the board.

a. Wholesale Market Design

1. Implementation of Nodal Market Design

The Commission adopted a rule in 2005 directing ERCOT to implement a nodal market design, and in 2006, it approved the Protocols as previously approved by ERCOT stakeholders for the operation of the nodal market.[48] The rule contemplated that the nodal market would begin operating in January 2009. In the summer of 2008, ERCOT announced that the nodal design would be delayed. In September 2008, the Commission and ERCOT contracted for an update of the cost-benefit study for the nodal market redesign. Testimony filed by ERCOT in November 2008 indicates that the preliminary budget for completion of the nodal project is now $660 million, up from $319.5 million, and the expected date for initiating the nodal market is December 2010. The preliminary budget and market "go live" date are not official, because they have not been approved by the ERCOT board of directors or the Commission.

In recent years, ERCOT and market participants have focused their efforts on developing the systems they will need to operate in the nodal market, and fewer proposals have been made or adopted for modifying the Protocols for the current zonal market. The major design issues that have arisen since January 2007 are described below.

2. Allocation of Replacement Reserve Costs

As noted earlier, ERCOT may purchase Replacement Reserve Service (RPRS), which is generation capacity kept in reserve to ensure there is always enough supply to meet electricity demand. In connection with the introduction of RPRS service, the ERCOT board of directors adopted a protocol revision that allocated the costs of the RPRS service.[49] The protocol revision was intended to assign the costs of the service to the market participants that were "short" in scheduling generation to meet load. Shortly after ERCOT began using the RPRS service in March 2006, it became apparent that the cost allocation for this service was having unexpected results. There were extensive

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48 *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 (Apr. 5, 2006).

49 Protocol Revision Request No. 676.

discussions of this issue in the ERCOT stakeholder forums, with one complaint filed against ERCOT by a market participant. The outcome of the complaint was to reinstate an allocation based on total load that a market participant serves.

3. Increased Procurement of Responsive Reserves

In January 2008, ERCOT increased its procurement of responsive reserves. These reserves represent additional generating capacity kept in reserve to be deployed within ten minutes, normally to deal with a generation shortfall caused by the loss of a generating unit or other system emergency. Prior to this increase in the procurement level, ERCOT's standard procurement of responsive reserves was 2300 megawatts. ERCOT concluded that it needed to increase the procurement, because it had found that some generating companies were not accurately representing to ERCOT the capacity available on their generating units. The most common source of inaccuracy was the failure of some generators to report that their generating units have a lower capacity during periods when temperatures are high. If the actual responsive reserves that are available are lower than the reserves that ERCOT believes are available, it may not have sufficient resources to maintain service to all customers during an emergency. A separate Protocol amendment permitted ERCOT to conduct unannounced tests of generator capabilities to verify the information reported by the operator.[50] The testing requirement appears to be resulting in more accurate reporting of generator capability, which permitted ERCOT to discontinue its procurement of additional responsive reserves in August 2008.

4. High Prices of May-June 2008

In May and June of 2008, ERCOT experienced very high prices in the wholesale electricity market. Several factors combined to cause these high prices, including unusually high temperatures during a time when a number of power plants and power lines were off-line for maintenance; very high natural gas prices; and severe transmission congestion on the North-to-South and North-to-Houston interfaces. In May and June 2008, there were a large number of days with temperatures over 100 degrees in Texas, resulting in increased electricity consumption for air conditioning. In addition, spot natural gas prices, which had been rising steadily since January 2008, reached a peak of over $13 per MMBtu in early July. These events happened right after the offer cap for the ERCOT balancing energy market increased pursuant to Docket No. 33490, approved on August 16, 2007, to $2,250 per MWh on March 1, 2008. Compounding the problem was a change made in January 2008, effective Mar 1, 2008, by the Wholesale Market Subcommittee to raise the shadow price cap to $5,600 per MWh.[51] In the midst of these events, in May and June congestion arose on the North-to-South and North-to-Houston interfaces that was difficult for ERCOT to manage. All of these factors contributed to higher wholesale prices during the spring, but the difficulty in managing the North-to-

[50] Protocol Revision Request No. 750.

[51] The increase in the shadow price cap was implemented without ERCOT board or Commission review.

South interface caused prices to reach or exceed the offer cap during a number of hours in May and June.

In its analysis of the congestion issue, the IMM concluded that ERCOT's definition of the transmission constraints comprising the interface between the North and South zones included constraints that were not effectively managed using zonal management techniques. The IMM recommended that the definition of the zonal interface be modified to focus on constraints that could be effectively managed using the zonal techniques, and the Commission held an emergency meeting on May 29, 2008 and another emergency meeting on June 11, 2008 to recommend this action to ERCOT. The Commission subsequently recommended a second change, affecting the calculation of market prices when congestion results in the exhaustion of balancing energy bids, to preclude market prices from exceeding the Commission-approved offer caps. The ERCOT board of directors also approved this recommendation. These modifications have seen success; the highest hourly balancing prices exceeded $1,000 on fourteen days in May and nine days in June, but only on two days in July and one day in August.

5. Impact of Hurricane Ike

Hurricane Ike, which struck the Houston-Galveston area on September 13, 2008, resulted in a significant, temporary reduction in electric load in the area, as transmission and distribution facilities were damaged, homes and businesses were destroyed or damaged sufficiently and could not receive electric power, and residents evacuated to seek shelter elsewhere. On Friday, September 12, a day before the hurricane struck, ERCOT peak load was about 49,000 megawatts and the load-weighted average balancing energy price for the day was $53.04. On Monday, September 15, ERCOT peak load was about 34,000 megawatts and the load-weighted average balancing energy price was $3.32. Load gradually recovered over the course of the week of September 15, and by Monday, September 22, ERCOT load was about 46,500 megawatts and the load-weighted average balancing energy price was $44.86. Spot natural gas prices at the Houston Ship Channel also fell briefly during this period, from about $7.40 per MMBtu on September 12 to about $5.50 on September 17. Natural gas prices rose back to the $7.00 per MMBtu range the following week.

6. Impact of wind development

During fall 2007, significant levels of congestion began to occur on the West to North interface, because transmission resources are insufficient to deliver growing levels of wind capacity to the load centers of the state. When too much generation is injected into the grid, prices become negative causing suppliers to pay ERCOT for the energy they generate. During periods of high wind and low ERCOT load in late winter and early spring, negative prices became a frequent occurrence in the West zone. In the near term, these constraints will likely continue, because the new CREZ transmission that is needed to relieve congestion will take several years to license, design and build. For wind farms that are in service or under development in the West zone, there is likely to be continuing congestion until the CREZ transmission facilities are completed.

The level of wind development has raised concerns about ERCOT's ability to manage the electric network during periods of high wind and low ERCOT load. One concern is the need for additional capacity reserves to compensate for the intermittent nature of wind generation. These capacity reserves are typically provided by quick-start natural gas units that come on line when the wind falls off. Other concerns come from the difficulty for operators to forecast changes in the output of wind generators. Wind generation output can change dramatically over a period of several hours, and the system operators who are responsible for maintaining the reliability of the network need to be able to see and, preferably, forecast changes in output. ERCOT has acquired a wind forecasting tool and is working to incorporate this tool into its system operations. Even if the changes in output can be forecast, the system operators will still need to have the ability to call on thermal generating resources to increase or reduce output to offset the combined impact of changes in wind generation output and load. Given the nature of wind generation, wind QSEs are not penalized for missing their scheduled output. ERCOT has established a task force to develop changes in operating and market rules to address these challenges.

b. Budget Oversight

ERCOT's current system administration fee of \$0.4171 per MWh was approved by the Commission in May 2006.[52] In June of 2008 ERCOT filed a request to increase the fee by about \$0.15 per MWh, but withdrew its request in September 2008 citing changed circumstances.[53] Specifically, ERCOT noted that due to the delay of the implementation date for the Texas nodal market, it reevaluated its 2009 revenue requirements and concluded that its current system administration fee was sufficient to fund its base operations for 2009 until a new nodal budget and schedule are developed, after which updated 2009 operating costs could be more accurately predicted.

An initial nodal market implementation surcharge of \$0.127 per MWh was approved by the Commission in May 2007.[54] This nodal surcharge is recovered from generators, while the administration fee is recovered from load entities. When the surcharge was approved, ERCOT estimated that total costs to implement nodal would be approximately \$248.9 million. In March 2008, ERCOT filed an application to increase the nodal surcharge to \$0.169 per MWh based on a revised estimate of the implementation costs of the nodal program of \$311.3 million. The Commission approved this increase in the nodal surcharge in May of 2008.[55] Also in May 2008, ERCOT announced that the

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[52] *Application of Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of the ERCOT System Administration Fee*, Docket No. 31824 (May 17, 2006).

[53] *Application of Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of the ERCOT System Administration Fee*, Docket No. 35785 (Aug. 22, 2008).

[54] *Application of Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of a Nodal Market Implementation Surcharge and Request for Interim Relief*, Docket No. 32686 (May 23, 2007).

[55] *Application of Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of a Revised Nodal Market Implementation Surcharge*, Docket No. 35428 (May 13, 2008).

Texas Nodal market would not be implemented by January 2009 as previously instructed by the Commission.

ERCOT continues to incur costs related to the nodal project, and in November 2008 ERCOT filed a request to increase the nodal surcharge to $0.38 per MWh on an interim basis to act as a "bridge" to prevent gaps in funding of the project until the cost benefit analysis is complete and the Commission and ERCOT determine the appropriate course of action.[56] According to ERCOT's filing, it forecasts that it will reach the limit of spending authorized by the Commission in January of 2009. The interim increase in the surcharge is designed to collect 75 percent of its current monthly spending rate of $12 million. Testimony filed by ERCOT in this proceeding indicates that the preliminary budget for completion of the nodal project is now $660 million, up from $319.5 million, and the expected date for initiating the nodal market is December 2010. The revised budget and implementation date must be approved by the Commission.

D. Oversight and Enforcement

The Commission protects consumers, the electric market, the reliability of the electric grid, and promotes fair competition by enforcing statutes, rules, and orders applicable to entities under its jurisdiction. The Commission's enforcement efforts in the electric industry focus on violations of PURA, the Commission's Substantive Rules and ERCOT protocols.

1. Commission Enforcement Structure

Prior to October of 2007, the Commission's enforcement efforts were handled through an agency enforcement coordinator, the Legal Division, and most agency personnel. In mid-2007 the Commission began reorganized its functions, and enforcement efforts were consolidated within a new division dedicated solely to enforcement, the Oversight and Enforcement Division (O&E). The reorganization was recognition of the need for increased enforcement in a competitive environment to guard against abuse in the wholesale and retail markets.

The Commission's new O&E Division was initiated on October 1, 2007. The O&E Division's goal is to promote compliance with PURA, and other applicable laws, and PUC Substantive Rules by electric and telecommunication service providers in order to protect customers and markets, and to ensure reliability. O&E works with the Commission Legal Division, as well as other divisions, in its investigations and enforcement activities. In the electric market, the main areas of oversight and enforcement are:

- Wholesale electric issues
- Retail electric issues
- Service quality

[56] *Application of Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of a Revised Nodal Market Implementation Surcharge*, Docket No. 36412 (pending).

- ERCOT protocol violations
- Market manipulation

The Commission's primary enforcement tool is the imposition of administrative penalties. The Commission's enforcement and administrative penalty authority is outlined in Chapter 15 of PURA, which provides for administrative penalties of up to $25,000 per violation per day.

2. Enforcement

The O&E Division has set up programs and processes to accomplish oversight of the industry through coordination with other Commission divisions regarding information on potential violations, and review or audit formal reports submitted to the Commission.

O&E has several sources of information regarding potential violations which might generate an investigation by the Division. These include the TRE, ERCOT, the IMM, other PUC divisions, filed reports, industry stakeholders, and other sources.

Once O&E has received information regarding a potential violation, the information is reviewed to determine if an investigation is warranted. If warranted, an investigation is opened and the provider is notified of the investigation. The investigation is conducted through research, meetings, and requests for information to the provider. An investigation may be concluded with a recommendation for action, if needed, or no further action if it is determined no violation occurred. If a violation is found, the provider may be sent a warning letter for a minor violation. Otherwise, the investigation is closed and the Notice of Violation (NOV) process begins.

The first step in the NOV process is to send a Pre-NOV letter to the provider describing the violation and recommending an administrative penalty. The provider has the opportunity to meet with Commission Staff to resolve the matter. The Staff and the provider may enter into a settlement agreement resolving the issues of the violation, the amount of administrative penalty, and any other appropriate remedies such as a mitigation plan. Settlement documents are filed with the Commission.

PURA provides for a three-level classification system for violations which includes a range of administrative penalties. The classification system includes the following factors for determining penalty levels:

- The seriousness of the violation;
- The economic harm caused;
- The history of previous violations;
- The amount of penalty necessary to deter future violations;
- The efforts to correct the violation; and
- Any other matter justice may require.

If the issues are not resolved through a settlement agreement, the Executive Director sends a Notice of Violation to the provider. This action initiates a contested case proceeding to resolve the issues of the violation and the administrative penalty. The NOV is referred to the State Office of Administrative Hearings and a hearing is conducted.[57] The SOAH judge issues a proposal for decision that is subsequently ruled on by the Commissioners to determine whether a violation has occurred and, if so, the appropriate penalty.

3. Current Penalty Activities

During the period from January 2007 through December 2008, the Commission assessed over $7 million in penalties for violations related to either the retail or wholesale electric markets. In addition, one settlement was reached on a retail violation that resulted in the expenditure by the company of $695,000 on customer education programs, rather than an administrative penalty.

The following table provides a summary of completed electric enforcement cases since January of 2007. In total during 2007 and 2008, Commission Staff opened 89 investigations for the electric industry and closed 56. An investigation is considered closed if it has either been closed with no NOV having been issued, or when an NOV has been issued. In addition, the Commission has one pending NOV regarding potential violations by American National Power.[58]

[57] While in most contested cases the Commission may conduct the hearing, in the Notice of Violation process the hearing must be conducted by a SOAH judge.

[58] *Notice of Violation by ANP*, Docket No. 34738 (pending).

Table 2: Summary of Electric Enforcement Cases

Company	Violation Type	Violation	Docket No.	Date of Final Order	Amount
TXU Portfolio	Market Power	Administrative penalty for notice of violation regarding withholding of power/market power abuse	34061	12/22/08	$15,000,000
TXU Energy Retail Company LP	Retail	Contract renewal practices	34357	7/23/07	$5,000,000
Direct Energy, LP	Retail	Contract automatic renewal provision of 25.475(e)(2)	34671	12/14/07	$695,000
First Choice Power	Retail	Contract renewal practices	35947	8/29/08	$500,000
Liberty Power	Retail	Deceptive marketing practices	36286	11/24/08	$32,000
Freedom Power	Retail	Disconnection of customers	33138	12/20/07	$21,050
Dynowatt LP	Retail	Violation of the Renewable Energy Credits Trading Program	35942	9/11/08	$550
Glacial Energy Inc.	Retail	Violation of the Renewable Energy Credits Trading Program	35990	9/12/08	$34,050
Mega Energy LP	Retail	Violation of the Renewable Energy Credits Trading Program	35966	9/12/08	$250
Sharyland Utilities, L.P.	Svc. Quality	Service quality standards	36128	10/24/08	$4,500
Centerpoint Energy	Svc. Quality	Service quality standards	36194	10/29/08	$178,750
AEP Texas Central Company	Svc. Quality	Service quality standards	36308	11/24/08	$165,000
AEP SWEPCO	Svc. Quality	Service quality standards	36309	11/24/08	$54,000
AEP North	Svc. Quality	Service quality standards	36307	11/24/08	$144,585
Cap Rock	Svc. Quality	Service quality standards	36311	11/24/08	$6,000
SPS	Svc. Quality	Service quality standards	36297	11/24/08	$48,000
Calpine	Wholesale	Violation of ERCOT protocol	33825	3/15/07	$21,582
Constellation Energy Commodities Group	Wholesale	Violation of ERCOT protocol	34154	5/31/07	$2,715
Formosa Ventures	Wholesale	Violation of ERCOT protocol	34183	5/31/07	$7,500
Reliant Resources	Wholesale	Violation of ERCOT protocol	34210	5/31/07	$111,581
Tenaska Power Services	Wholesale	Violation of ERCOT protocol	34182	5/31/07	$166,695
Suez	Wholesale	Violation of ERCOT protocol	34134	6/11/07	$2,945
Texas-New Mexico Power Company	Wholesale	Violation of ERCOT protocol	34328	6/22/07	$5,000
Garland Power & Light System	Wholesale	Violation of ERCOT protocol	34368	7/23/07	$5,000
City of Garland	Wholesale	Violation of ERCOT protocol	34381	7/26/07	$1,035
Tenaska	Wholesale	Violation of ERCOT protocol	34456	7/31/07	$4,000
Xtend	Wholesale	Violation of ERCOT protocol	34014	8/17/07	$21,922
Xtend	Wholesale	Violation of ERCOT protocol	34905	11/20/07	$2,000
AEP	Wholesale	Violation of ERCOT protocol	35215	2/8/08	$15,000
Suez Energy Resources NA, Inc.	Wholesale	Violation of ERCOT protocol	35650	10/29/08	$116,000
BP	Wholesale	Violation of ERCOT protocol	36256	11/5/08	$132,567
Brazos Electric	Wholesale	Violation of ERCOT protocol	36371	12/5/08	$6,000
American National Power	Wholesale	Violation of ERCOT protocol	34738	N.A.	Ongoing
TOTAL					$22,505,277

E. Non-ERCOT Utilities: Market Development Activities

1. Entergy Retail Access

On December 29, 2006, Entergy Gulf States, Inc. (EGSI) filed a transition to competition plan (TTC Plan) as required by PURA § 39.452(g).[59] EGSI requested that approval of its plan be considered in a rulemaking proceeding. On February 16, 2007, the Commission issued its Order on Threshold Issues, ruling that this matter should be processed as a contested case. EGSI requested that the Commission approve its request to change from its current power region, the SERC Reliability Corporation (SERC), to the Electric Reliability Council of Texas (ERCOT) as an "overarching initial determination." EGSI argued that it should not be required to pursue the option of moving to the Southwest Power Pool (SPP) because EGSI believed that full customer choice cannot reasonably be expected to be implemented in the SPP, at least in the foreseeable future.

On October 24, 2007, the Commission issued an order that abated this proceeding and instructed EGSI to request SPP staff to conduct an analysis similar to the Phase II Entergy Integration Report completed by ERCOT in 2006. The Commission also clarified its order abating this docket, and ordered EGSI to provide an updated analysis of the costs and benefits of EGSI's remaining in the Southeastern Electric Reliability Council power region.

On May 8, 2008, the Commission considered status reports filed in this docket by SPP and ERCOT on April 29, 2008. As a result of this consideration, the Commission accepted SPP's new estimated timeframe for completion of its integration study, and directed ERCOT to update its Phase II Report contemporaneously with SPP's study. The study efforts by SPP and ERCOT are ongoing.

2. Fuel Rule Amendment

In August 2008, the Commission adopted an amendment to P.U.C. SUBST. R. 25.237 relating to Fuel Factors.[60] The amendment maintains the traditional fuel factor filing on a fixed schedule and a prescribed filing package and adds the option, and procedure, for a utility to determine its fuel factor using a Commission-approved, utility-specific fuel factor formula. In addition, a utility using the traditional method will now be able to revise its fuel factor on a fixed, four-month schedule rather than a fixed, six-month schedule. A utility using the new formula will be able to revise its fuel factor as often as every four months, except for the month of December, and will not be subject to a set schedule.

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[59] *Application of Entergy Gulf States, Inc.'s for Transition to Competition Plan (TTC Plan)*, Docket No. 33687 (pending)

[60] *Rulemaking to Amend Substantive Rule §25.237 Fuel Factors*, Docket No. 34914 (Aug. 15, 2008).

F. Customer Education Activities

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 sixth and seventh years of the campaign (September 2006 through August 2008) continued the previous years' focus on educating Texans about Electric Choice and their options in electric providers and plans. The integrated education campaign uses a number of means, 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

The Commission conducted a number of activities to improve the public visibility of retail choice, largely designed to let electric customers know that that the campaign website, www.PowerToChoose.org, and call center are neutral, credible sources of information about retail choice.

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 more than three million listeners a year in FY 2007 and FY 2008.

Recruitment of Education Partners. The Commission recruited approximately 80 local police departments across the state as well as other community groups to distribute 350,000 pieces of literature and promotional items during the "National Night Out" events in 2007 and 2008 and during other major outdoor events in 2008 (Earth Day, 4th of July). These activities reached an estimated 875,000 people during the 2007-2008 biennium.

TAB NCSA Program. The Commission participated in the Texas Association of Broadcasters' Non-Commercial Sustaining Announcement program, which allowed the Commission's public service announcements on Electric Choice to be aired throughout competitive retail electric markets in Texas at about 20-25 percent of the cost of buying commercial airtime with the same reach.

Energy Star Tax-Free Weekend Video News Release. During Memorial Day Weekend 2008, the Commission distributed a video news release statewide that alerted consumers to the Comptroller's tax-free weekend for energy-efficient appliances and related products. The releases were picked up by television stations across the state and reached 7.3 million Texans with a total cost of about $13,000.

2. Websites

The Texas Electric Choice campaign website, www.PowerToChoose.org, and its Spanish-language counterpart, www.PoderDeEscoger.org, are vital parts of the customer education process. During FY2008, the website was expanded to include information on the financial condition of retail electric providers, their complaint records at the

Commission, and other data that customers would find useful when evaluating retail electric offers. Key statistics for these websites during the 2007-2008 biennium include:

Table 3: PowerToChoose Website Statistics

Unique Visitors	1,511,536
Visits	3,782,167
Downloads	528,461

3. Internet Search Engine Marketing

The campaign initiated a targeted Internet search engine marketing program in the summer of 2007. The goal of the program was to drive Internet users to the PowerToChoose website to shop for a retail electric provider. Internet users who did Google and Yahoo! searches on terms relating to electric service in Texas would generate banner ads on the right column of the search engine results page linking the user to the PowerToChoose website. When a user clicked on the link to the site, the Commission paid a small fee to the search engine provider. During the summer of 2007, more than 16,000 people followed the link to the PowerToChoose website and clicked through to the site's retail offers page. During the summer of 2008, the program caused more than 51,000 people to compare offers on the PowerToChoose site.

4. Answer Center

The PowerToChoose 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 five 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 2007 and 2008 included:

Table 4: Answer Center Call Activity

Total Calls	324,188
Total Representative-assisted Calls	246,430
Total Spanish-Language Calls	29,285

5. Educational Literature

Brochures, fact sheets and other educational materials are distributed via mail, 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 nearly 1.1 million information products during 2007 and 2008. The primary publication of the Texas Electric Choice campaign, "The Official Guide to Electric Choice", won the top award for brochures at the 2008 annual conference of the National Association of Government Communicators.

G. Low Income Discount: System Benefit Fund

The 80th Legislature made no changes to PURA § 39.903, which governs the System Benefit Fund and the electric rate reduction program. The Legislature did appropriate $80 million for Fiscal Year 2008, from which low-income discounts were provided in September 2007 and May through August 2008. It also appropriated $90 million for the Fiscal Year 2009, for low-income discounts in September 2008 and May through August 2009. Also, during the 80th Legislature, House Bill 15 was adopted, which appropriated $30 million for the rate reduction program during the summer months of Fiscal Year 2007. Of the funds for FY 2007, $24,783,562 were distributed to 982,324 recipients. For FY 2008, not yet finalized figures show $69,605,211 distributed among 1,801,763 recipients.

III. Effects of Competition on Rates and Service

In the last two years, REPs and consumers in the Texas retail electric market have faced large price fluctuations in the wholesale electric market. These fluctuations have made it difficult to predict costs. Nevertheless, new REPs continued to enter the market, selling plans with an array of terms of service, from one month to multiple years, up to 100 percent renewable energy, fixed rates and variable rates. In the residential sector, most retail customers have over 25 REPs offering as many as 90 different rate packages to choose from.

In January 2007, the Texas retail electric market achieved a milestone when the regulated Price-to-Beat (PTB) electricity rates expired and all retail electric customers began to be served under competitive rates. By that time, over 37 percent of residential and small commercial customers, representing 58 percent of the eligible load, had already switched service to competitive providers, and many others were being served at competitive rates by incumbent providers formerly referred to as affiliated REPs (AREPs), which had been allowed in 2005 to begin offering customers rates other than the PTB. As of June 2008, over 44 percent of all customers had taken advantage of the opportunity to switch to a competitive REP, including 43 percent of residential and nearly 60 percent of commercial customers.

Including the largest users of electricity in the market, 61.4 percent of electricity sold in the competitive market in Texas is supplied by providers other than the legacy provider. As of June 2008, nearly 2.9 million Texas customers, including over 2.4 million residential customers, have chosen to receive service from providers other than the legacy provider. Additional customers have explicitly chosen to take service from a legacy provider, either by selecting it as their initial provider upon move-in, switching to another REP and then switching back, or simply by signing a contract with the legacy provider to gain lower or more secure rates for the term of a contract.

The last two years have seen significant volatility in the prices of natural gas which fuels over half of the generation available in the wholesale market in ERCOT. Natural gas price volatility has resulted in significant swings in retail price offers and unexpected high prices for some customers. For example, when four small REPs were unable to meet their obligations in the market during a period of very high wholesale prices in April and May 2008, customers were transferred to the Providers of Last Resort (POLRs) until they could select a new provider. While these events did frustrate customers and lead to additional rule changes to further protect customers, the systems to handle the mass transfer of customers to the POLRs worked well. Most customers were transferred to the POLR or to a new REP of their choice within a few days, and no customers lost service due to the failure of their provider. Since the transfer, most of the affected customers have chosen a retail product from the POLR or a new provider at a lower cost than the POLR rate.

A. Effect of Competition on Rates

1. Wholesale Market Prices

There are three major components to the ERCOT wholesale market: the bilateral market comprises 95 percent of all power traded; the balancing energy market makes up the other 5 percent of energy bought and sold and is used by ERCOT to match supply and demand in the short term; and the ancillary service markets is used by ERCOT to procure capacity to maintain system reliability.

Natural gas prices are very significant in the Texas market as natural gas is a primary fuel and is frequently the fuel for the generating units that are the last dispatched in the balancing energy market. As a result, natural gas-fueled generation typically sets the market price for energy in the balancing energy market, and there is close correlation between that market and bilateral energy prices. In general, Texas wholesale power prices tend to follow natural gas prices.

Natural gas prices in 2007 remained mostly between $5 to $8 per MMBtu. Gas prices increased in 2008 reaching their peak on July 3rd at about $13 per MMBtu. Electricity prices in the balancing energy market generally followed natural gas prices during the first half of 2008, and the balancing energy prices were quite volatile. The balancing market experienced a series of price spikes in May and June, resulting from transmission congestion. Congestion resulted in much lower prices in the west zone. By the end of August 2008, natural gas prices had dropped back to $7 to $8 per MMBtu with wholesale electricity prices retreating to $60 to $70 per MWh range and by December 2008, natural gas prices were $5 to $6 per MMBtu with wholesale prices retreating to $40 to $53 per MWh. The close correlation among bilateral, balancing, and gas prices also returned, because wind output during the summer had less impact on electricity prices.

Bilateral wholesale prices were low in 2007. This was due in part to significantly lower than normal temperatures in the summer of 2007.[61] In general, the wholesale market prices for capacity and energy in ERCOT were stable in 2007 in contrast to 2008. In 2008, prices in the balancing energy market ranged from $11 to over $4,000 per MWh. The extremely high prices were the result of zonal congestion issues that were subsequently resolved through the action of the ERCOT board of directors as directed by the Commission. The September 2008 balancing energy prices dropped significantly as natural gas prices fell.

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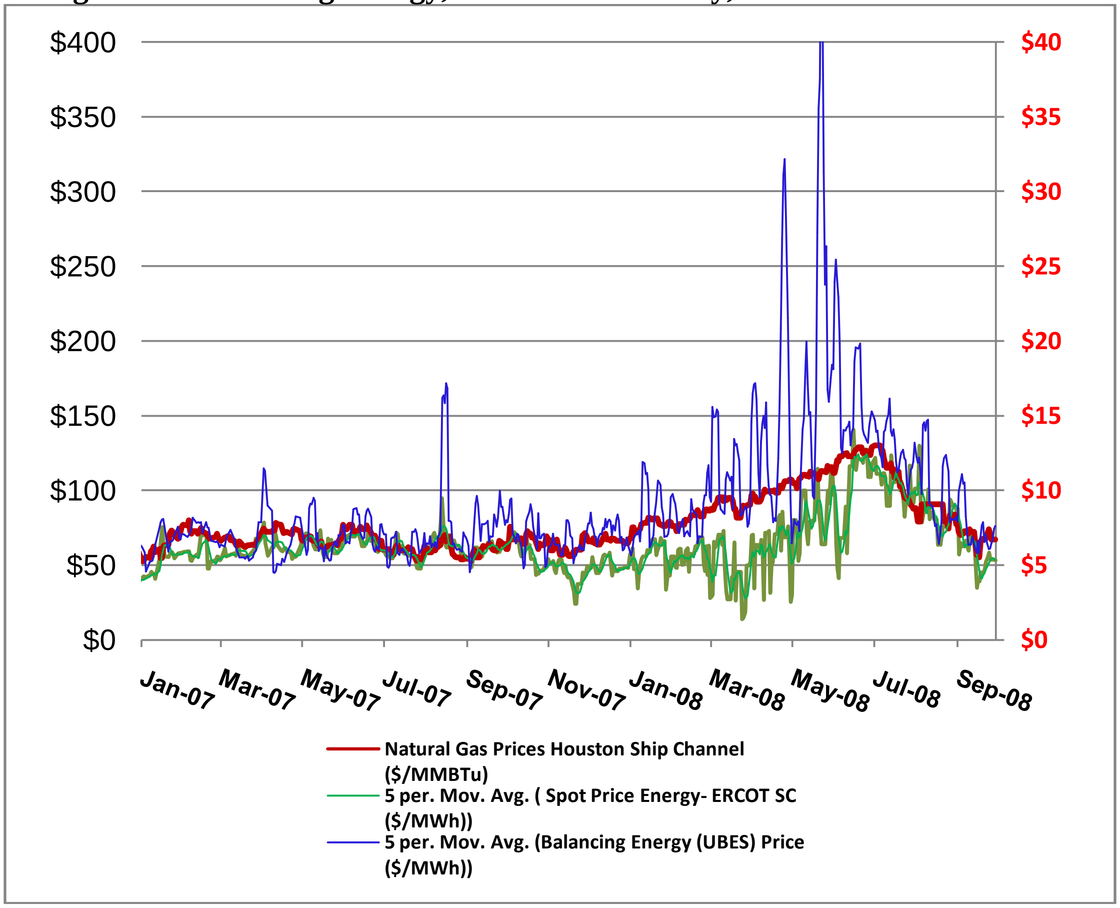
[61] *2007 State of the Market Report for the ERCOT Wholesale Electricity Markets*, Potomac Economics, Ltd., p. vii.

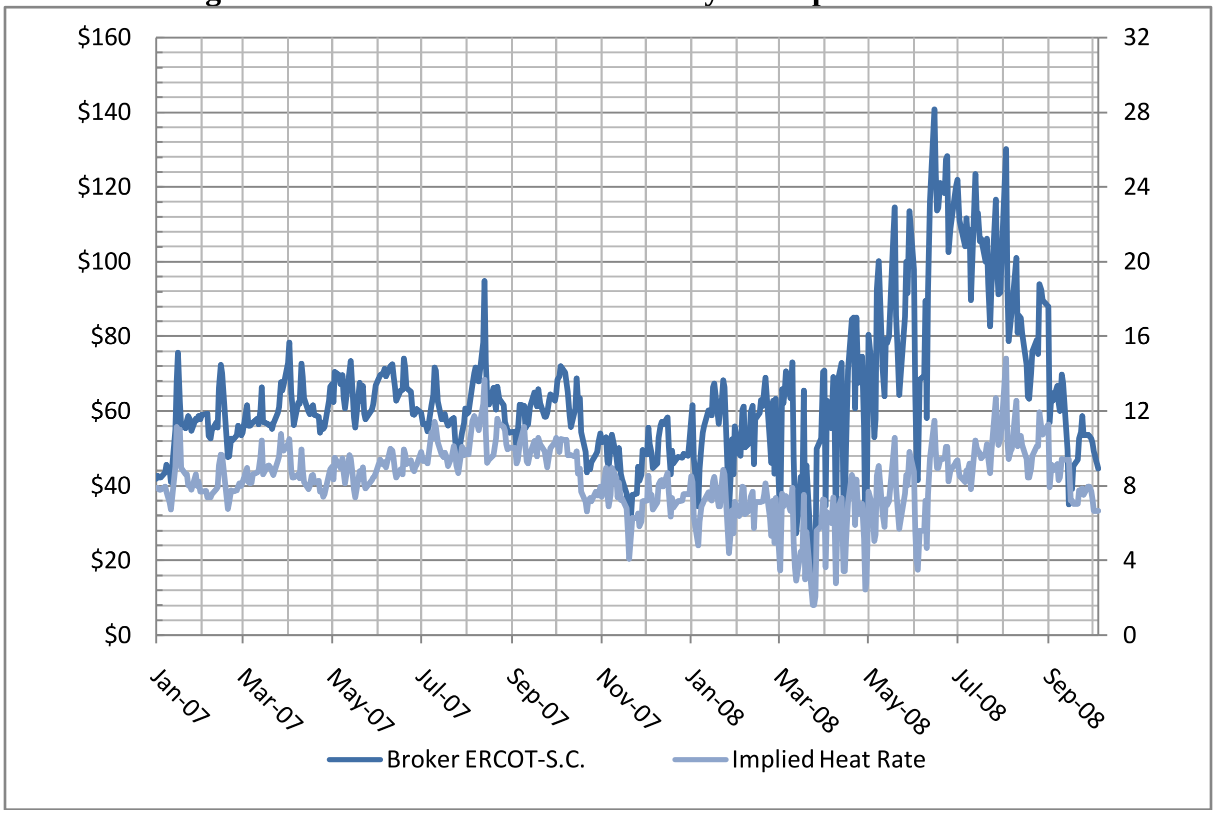
Figure 2: Balancing Energy, Bilateral Electricity, and Natural Gas Prices



a. Bilateral Market Prices

The ERCOT market relies on bilateral contracts between buyers and sellers of electricity as the principal mechanism for trading power. Bilateral contracts are privately negotiated between buyers and sellers, and encompass a variety of durations, 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, the length of the contract, 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 figure below shows the trend for daily electricity prices and the implied heat rate associated with those prices. The implied heat-rate is a way of comparing prices that removes the impact of the fluctuating cost of natural gas. The heat rate measures the amount of heat from fuel that is required to generate a unit of electric energy. The implied heat rate is calculated by dividing the market price by the price of natural gas. The figure shows that from October 2007 to May 2008 heat rates fell from a range of 8 to 10 to a range of 6 to 8. The implied heat rate rose during the summer of 2008, as demand for electricity rose and wind generation decreased. Electricity prices were lower, relative to the cost of natural gas, presumably as a result of large amounts of wind energy being sold in the market.

Figure 3: ERCOT Bilateral Electricity vs. Implied Heat Rate



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. ERCOT procures balancing energy in each of the major congestion zones. At times when there is no transmission congestion, prices in each zone are equal. When transmission congestion limits the transfer of power between zones, prices will typically be higher in those zones that are transmission constrained.

Price volatility in the balancing energy market 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 the demand for electricity. The level of wind generation also affects prices in the balancing energy market.

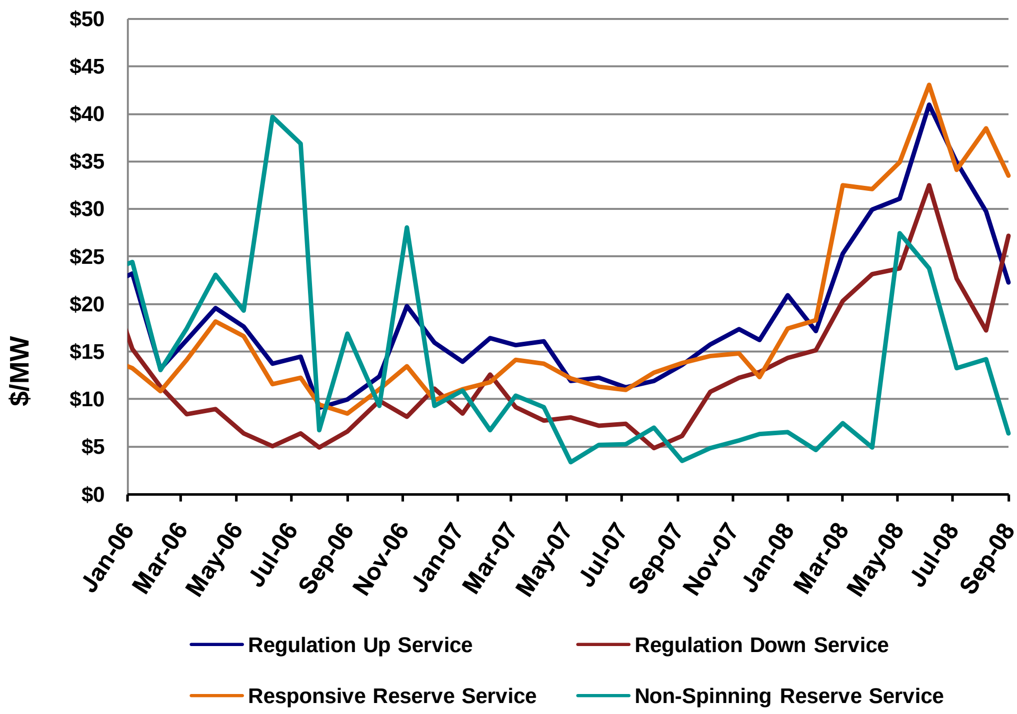
The daily weighted average price for balancing energy in ERCOT averaged $56.35 per MWh in 2007 and $83.37 per MWh for January through October 2008. The 2008 increase in the average BES (balancing energy service) price reflected the increase in natural gas prices and ERCOT congestion issues. Since September, prices have been lower, as wind output has increased, demand is lower, and natural gas prices have remained below $8.00.

Congestion levels were reduced in late June 2008 through changes in the way that ERCOT manages congestion. Ongoing congestion that affects west zone wind production is a result of insufficient transmission capacity, relative to the amount of wind generation facilities, and it will take time and investment in transmission to resolve this congestion.

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 load. Market participants may "self-provide" the capacity or rely on ERCOT to acquire it for them through a centralized auction. The monthly weighted average prices for these capacity services (regulation up, regulation down, responsive reserve, and non-spinning reserve) remained fairly stable from January to September of 2007. Capacity prices started to increase in September 2007, and reached levels in June 2008 that were unusually high for 2007 and 2008. High gas prices and the high BES prices in May and June of 2008 appear to have pushed ancillary service capacity prices to these high levels. Capacity prices hit a monthly record high in excess of $40 per MW in June.

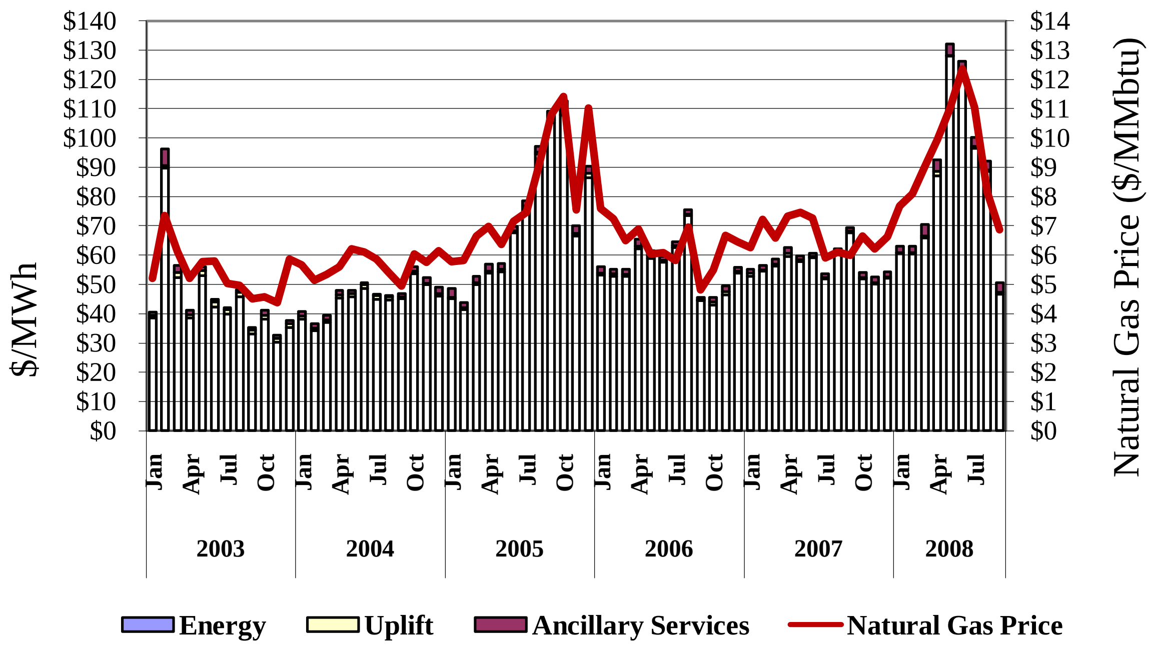
Figure 4: Monthly Weighted Average Ancillary Service Prices



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. This construction assumes that a customer buys all of its energy from the ERCOT operated energy and capacity markets. Energy costs make up the bulk of the all-in cost, with ancillary services and uplift charges accounting for about five percent to eight percent of the total. Uplift charges represent services that ERCOT purchases for the benefit of the market but cannot assign to a specific market participant and 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.[62]

Figure 5: Average All-in Price for Electricity in ERCOT



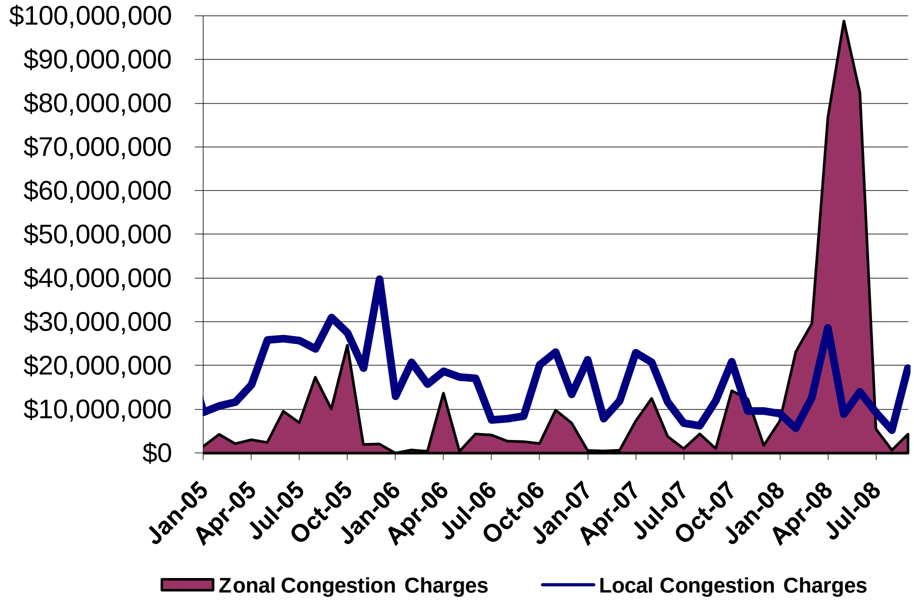
The preceding figure indicates that natural gas prices are the primary driver of the trends in electricity prices in ERCOT. Short-term events, such as tight capacity and congestion costs can be additional factors that influence electricity prices, but natural gas prices are the key factor that influences the level or wholesale electricity prices.

[62] 2007 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd., p. xi.

e. Congestion

The year 2008 has been a dynamic period for congestion. Congestion resulted in instances in which the Market Clearing Price for Energy (MCPE) in the balancing energy market to reached $4,233 per MWh and pushed the interzonal congestion cost (see Figure 6) to more than $328 million for the first nine months of 2008. This compares to $114 million in interzonal congestion costs for all of 2007. The interzonal congestion was a consequence of a number of factors including limited North to South transmission, outage of certain thermal units along the North to South CSC, increased load demand in the south zone, wind production in the west zone that exceeded the capability of the transmission system to move it to other zones, and issues relating to ERCOT congestion management procedures. In addition, the wholesale balancing energy settlement procedures included a shadow price cap that was raised to $5,600 per MWh, effective March 1, 2008.[63] The congestion management issues have been corrected and the price cap in the settlement procedures has been revised, through amendments to the ERCOT Protocols. Interzonal congestion related to wind energy production is likely to persist during the non-summer months until additional transmission facilities are built between the west zone and other zones.

Figure 6: Zonal and Local Congestion Charges



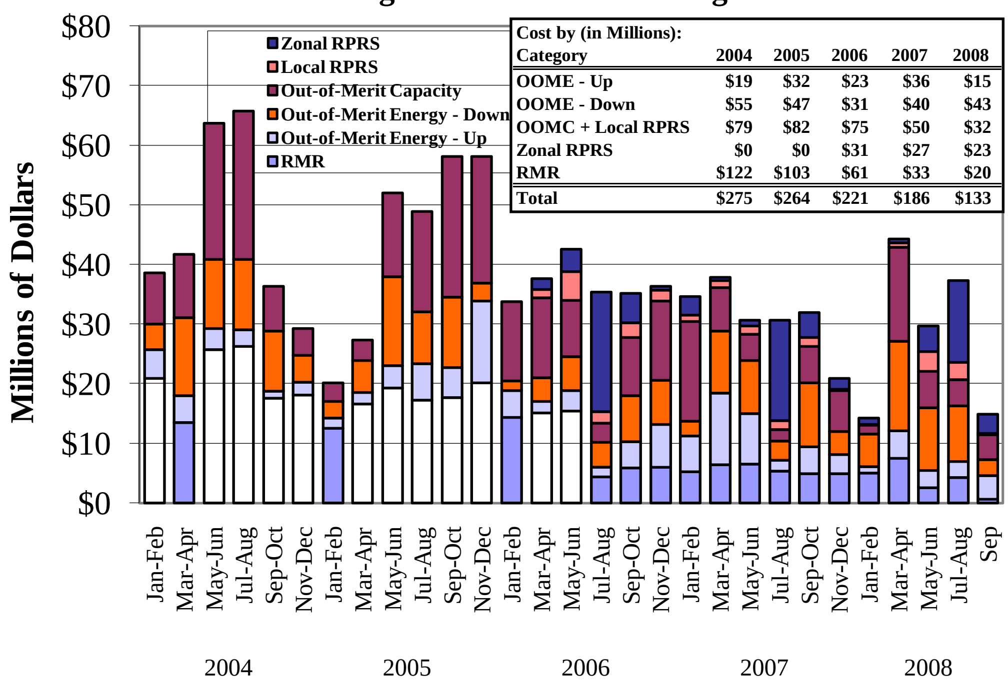
One of the most important functions of any electricity system is to manage the flows of power over the transmission network, limiting additional power flows over transmission facilities before they reach their operating limits. In ERCOT, constraints on the transmission network are managed in two ways. First, ERCOT is made up of zones with

[63] The increase shadow price cap was not approved by the full ERCOT board or by the Commission.

constraints between the zones managed through the balancing energy market. The balancing energy market relies on zonal prices to increase energy production in one zone and reduce it in another zone to manage the flows between the two zones when there is interzonal congestion. Second, constraints within each zone (*i.e.*, local congestion) are managed through the re-dispatch of individual generating resources. Both of these tools impact wholesale prices either by elevating balancing energy prices or by increasing the local congestion charges that are passed on to load.[64]

ERCOT manages local (intrazonal) congestion using out-of-merit dispatch (OOME up and OOME down), which causes units to depart from their scheduled output levels. When capacity is insufficient to meet local reliability requirements, ERCOT sends OOMC instructions for offline units to start up to provide energy and reserves in the relevant local area. ERCOT also enters into RMR agreements with certain generators that are needed for local reliability and would otherwise be mothballed or retired. When these RMR units are called upon to provide energy for reliability purposes, out of the order that economics would require, they receive revenues specified in the agreements, rather than standard OOME or OOMC payments. The following figure shows the out-of-merit energy and capacity costs, including RMR costs, from 2004 to 2008.[65]

Figure 7: Intrazonal Congestion



[64] 2007 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd., p. xxxii.

[65] 2007 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd., p. xxx.

Intrazonal or local congestion in 2008 has not seen the extreme fluctuations that have been present in the interzonal arena. The costs for resolving local congestion is $133 million for the first nine months of 2008, less than the $186 million for all of 2007.

f. Resource Development

Utilities in ERCOT continue to add transmission facilities to the network, and developers continue to add generation resources, on a competitive basis, to meet the needs of a growing Texas economy. Since 2004-05, several thousand megawatts of wind and thermal generation capacity and over $2.8 billion in upgrades to the ERCOT high-voltage transmission infrastructure have been built. Looking forward, ERCOT reports on generation capacity, demand, and expected reserves project that reserve margins will be well above the 12.5% target minimum through 2014.[66] Significant generation capacity additions are projected to be made in both North and South Texas, including 1,440 megawatts of coal-fired generation capacity in the north congestion zone in 2009 and 1,600 megawatts of coal-fired generation capacity in the south congestion zone in 2010.

2. Retail Market Development and Prices

a. Available Choices for Customers

An important measure of the success of retail market competition is the number of providers in the marketplace competing to provide service to customers. Texans have an abundance of service offers to choose from. By June 2008, 85 REPs were providing electric service to customers. There are 43 REPs serving at least 500 residential customers, and residential customers throughout the competitive market have multiple providers from which to choose. As of September 29, 2008, customers visiting the Commission's PowerToChoose website would find as many as 27 REPs offering products throughout the competitive area of the state. These REPs were offering as many as 96 different products in various territories, including 13 REPs which were offering, between them, 23 different renewable energy options.

The number of REPs and offers has increased steadily since 2002. Residential customers have at least 50 percent more options than they did at the end of 2006.

[66] These projections are current best estimates with no guarantee, especially with current market conditions, that all projects will be built. The Commission will continue to monitor the generation capacity and reserve margins in ERCOT.

Table 5: Number of REPs Serving Residential Customers by Service Territory

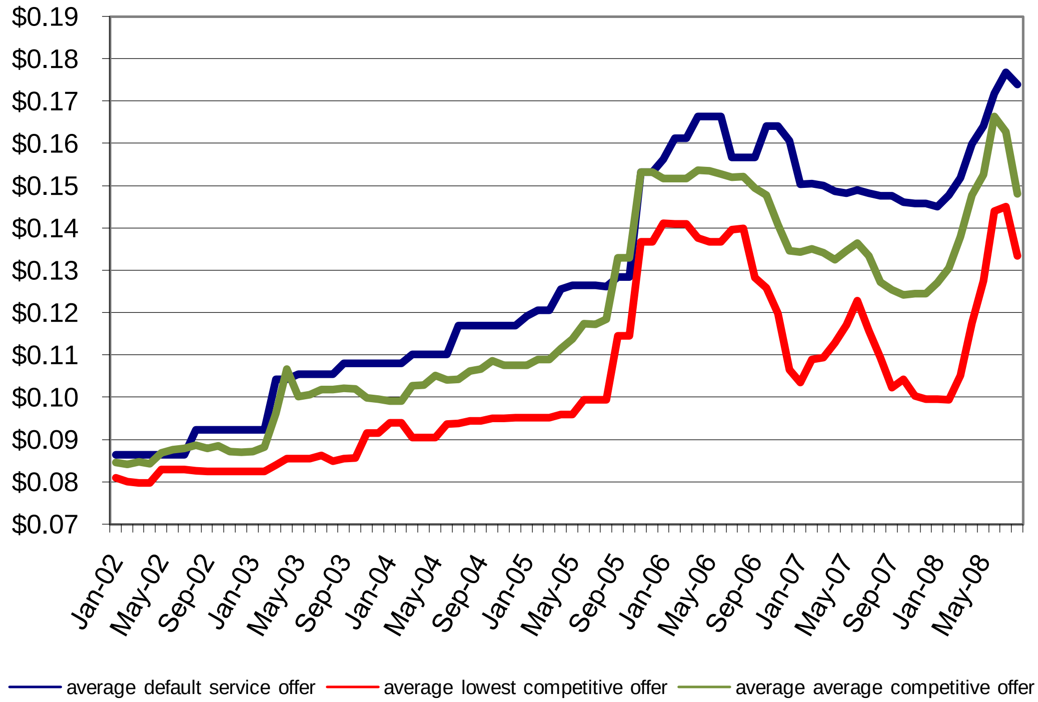
Transmission and Distribution Utility	Number of REPs Serving Residential Customers (Incl. affiliated REP)	Number of Residential Products	Number of Renewable Products
Oncor	27	96	22
CenterPoint	26	85	20
AEP TCC	27	91	23
TNMP	25	84	21
AEP TNC	27	90	20

b. Residential Rates

On January 1, 2002, all existing residential customers were placed on price to beat rates that were established at a discount of six percent off the then-existing residential rates. As provided by PURA on 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 continued until January 1, 2007, at which time all customers began to be served at rates set by market forces.

Since January 2002, AREPs or legacy providers have increased their standard rates by 73 to 114 percent. These price increases resulted primarily from changes in the price of natural gas, and represent changes which would have occurred in either a competitive or a regulated market. Price increases by the legacy providers have also played a major role in allowing competitive REPs the opportunity to compete in the marketplace. The following graph shows the average legacy provider standard residential rate across all service territories, along with the average and lowest competitive offers across all service territories. As of September 2008, savings of between 14 percent and 29 percent relative to the legacy provider's standard rate are available for a typical 1,000 kWh per month residential customer.

Figure 8: Average Incumbent Service Offer vs. Competitive Offers



Texas rates from legacy providers are higher than the rates in many other states, because Texas is more reliant on natural gas than most other states. As in Texas, electric rates in other states dependent on natural gas have also risen significantly. The following table shows the current residential price of power for major utilities in states with a high dependence on gas-fired generation.

Table 6: Retail Price for Electricity from Gas-Dependent Retail Providers

Utility	State	Avg. price in cents per kWh	Statewide gas share of generation[67]
San Diego Gas & Electric	California	16.00	47.6%
TXU Default Rate	Texas	15.40	48.6%
Southern California Edison	California	15.26	47.6%
Pacific Gas & Electric	California	14.86	47.6%
Reliant Default Rate	Texas	13.7	48.6%
Sierra Pacific	Nevada	13.41	46.4%
Tampa Electric Company	Florida	12.84	38.1%
NSTAR	Massachusetts	12.71	45.0%
TXU Lowest Offer	Texas	11.70	48.6%
Gulf Power	Florida	11.38	38.1%
Reliant Lowest Offer	Texas	11.0	48.6%

[67] Statewide gas share of generation estimates from July 2005 to July 2006.

At the end of 2008, natural gas prices fell sharply from their summer peak but, at around $6, remained double the settlement prices of 2001. Despite this doubling in cost for natural gas, the most competitive offers in the Texas power market have only increased an average of 15.4 percent for fixed rates and 5.7 percent for variable rates since the market deregulated in 2002.

Figure 9: Lowest Retail Fixed Rates in Texas

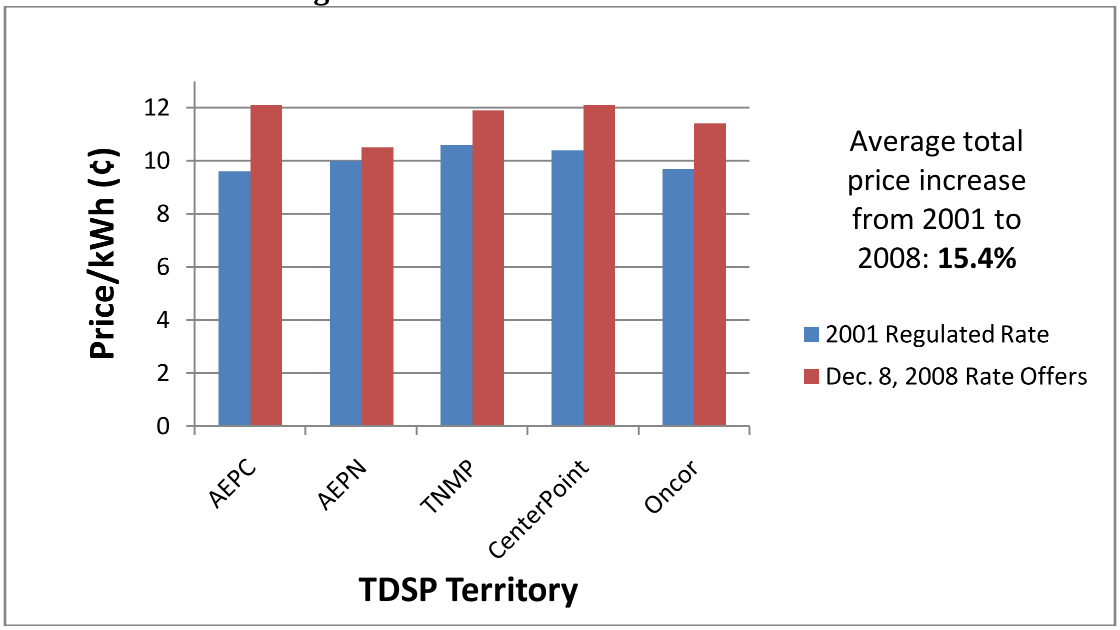
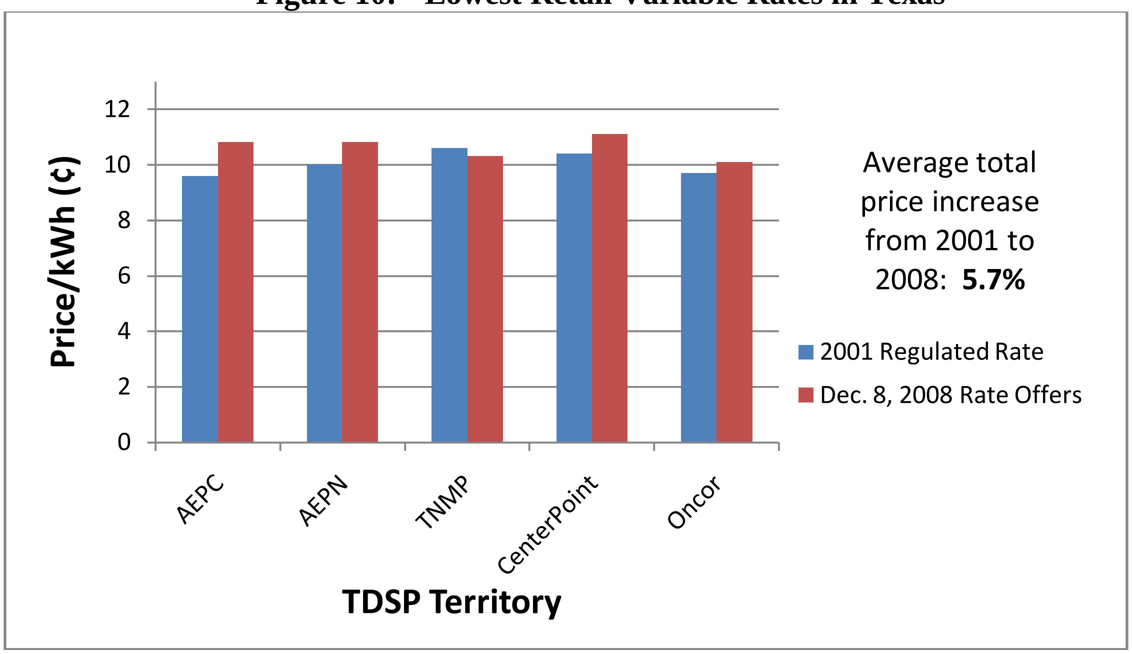


Figure 10: Lowest Retail Variable Rates in Texas



B. Switching Activity

As of June 2008, nearly 2.9 million individual customers were taking service from REPs other than one of the legacy providers, based on data reported to the Commission by the Transmission and Distribution Utilities (TDUs). This represents over 44 percent of all customer premises in service areas open to customer choice. Of these, 83 percent, or approximately 2.4 million, are residential customers and another 420,000, or 14.6 percent, are customers taking delivery at secondary-voltage levels, such as retail establishments and offices. The balance consists of approximately 5,500 large facilities taking high-voltage power, such as factories and refineries, and 48,000 lighting systems, such as streetlights and security lighting.

In June 2008, a total of 12.8 million megawatt-hours (MWh) of electricity was used by customers of a REP other than a legacy provider, representing approximately 61.4 percent 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 large commercial and industrial customers comprise a significant percentage of Texas energy usage, and these customers have higher switching rates than smaller customers who use less power. Though residential customers represent 83 percent of total switches, they represent only 26 percent of the electricity sold to switched customers in June 2008.

As the following figures demonstrate, switching rates vary somewhat by service area, with the lowest rate of switching in the Oncor service area, at 40.49 percent, and the highest rate in the AEP North service area. The lowest level of energy consumed by customers of competitive REPs is also in the Oncor service area, at 40.2 percent, and the highest is in the AEP North service area, at 81.58 percent.

Figure 11: Customers by REP Status

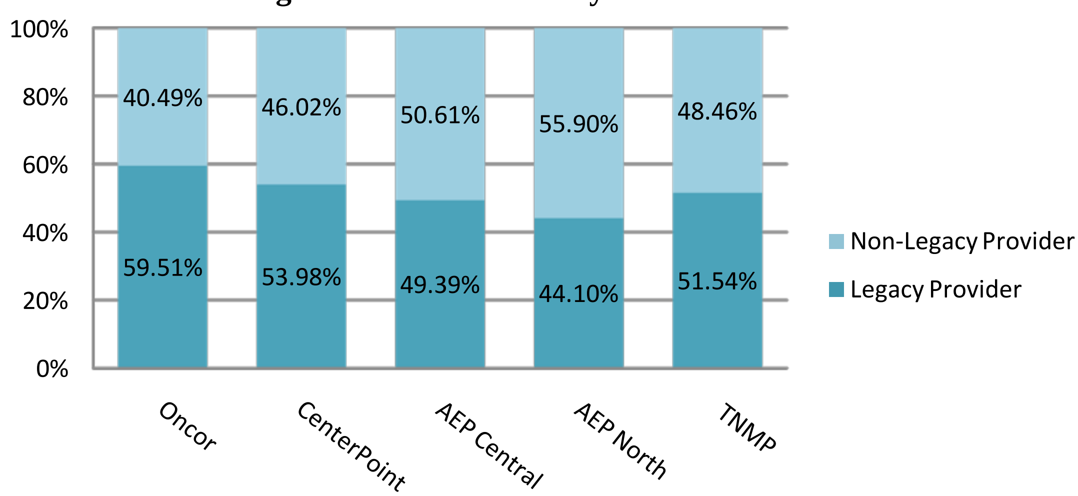
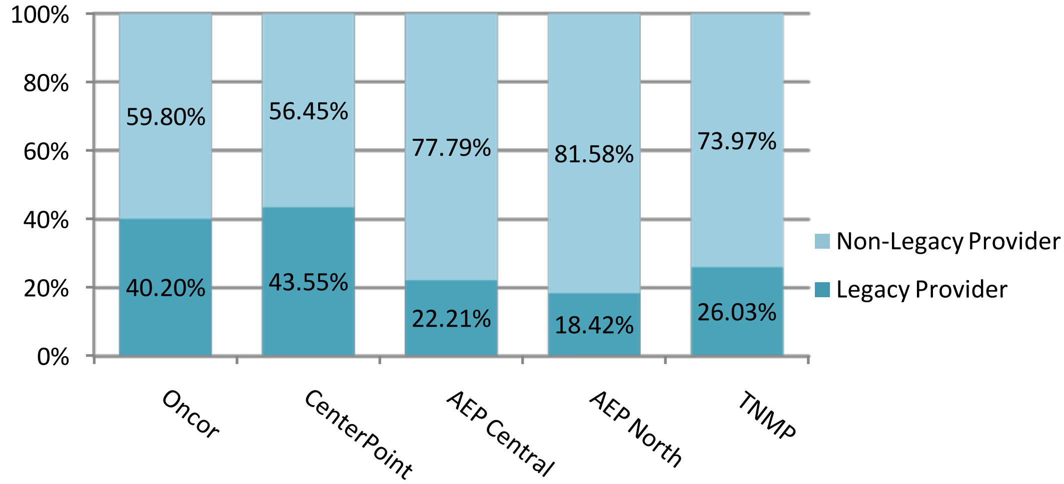


Figure 12: Energy Sold by REP Status



1. Residential Customers

There has been a consistent trend of residential switching, with about seven percent of residences annually joining the ranks of customers of non-legacy providers since 2002. Though retail competition exists in a number of other states, including New York, Michigan, Illinois, and several New England states, few REPs have attempted to compete for residential customers in those states and few residential customers have elected to change providers.[68] In New York, 14.3 percent of residential customers had switched by the end of 2007, with the typical residential customer having about seven options available.[69] This switching rate compares with the 43.9 percent switching rate in Texas.

Competing REPs originally focused their efforts on winning customers in the large urban markets of Houston and Dallas-Fort Worth, but have now branched out with most residential REPs marketing throughout the state. REPs have been most successful in the area that once had the highest PTB rate, the relatively rural AEP TNC (previously West Texas Utilities) territory where 57.5 percent of residential customers have switched. In the other service territories 39.8 percent to 49.4 percent of residential customers are with competitive REPs. These percentages do not account for the number of residential customers who originally switched to a new provider, but returned to the legacy provider at a later date. The switching rates also do not explicitly recognize that customers make a choice when they initiate service, and the percentages above designate new customers who have selected a legacy provider as not having switched.

[68] *Competition in Illinois Retail Electricity Markets in 2005*, Illinois Commerce Commission (May 2006), p 5.

[69] 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.

Figure 13: Residential Customers with a non-legacy REP by Service Territory

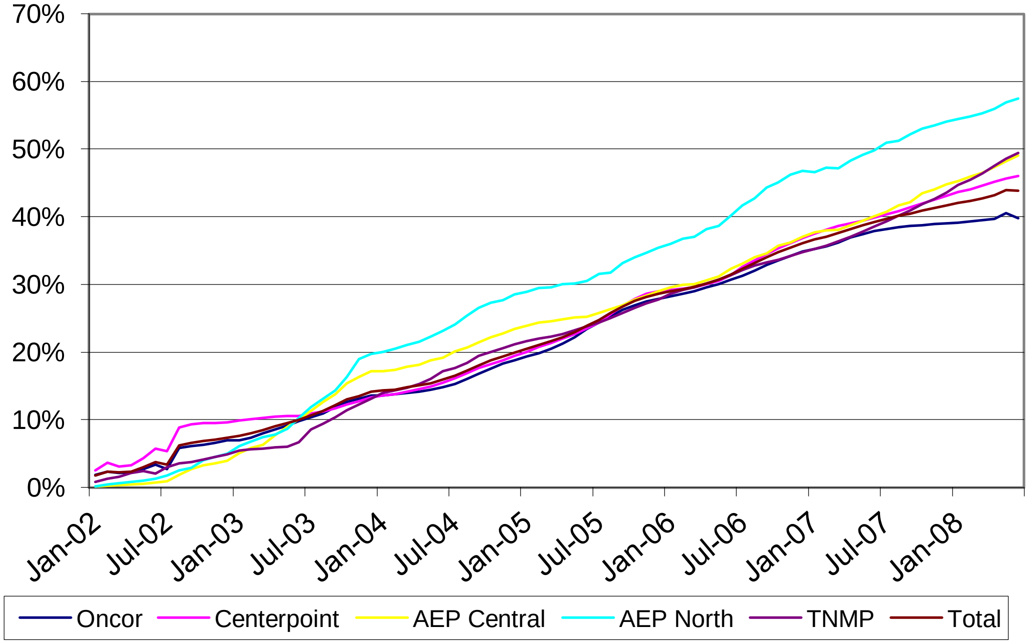
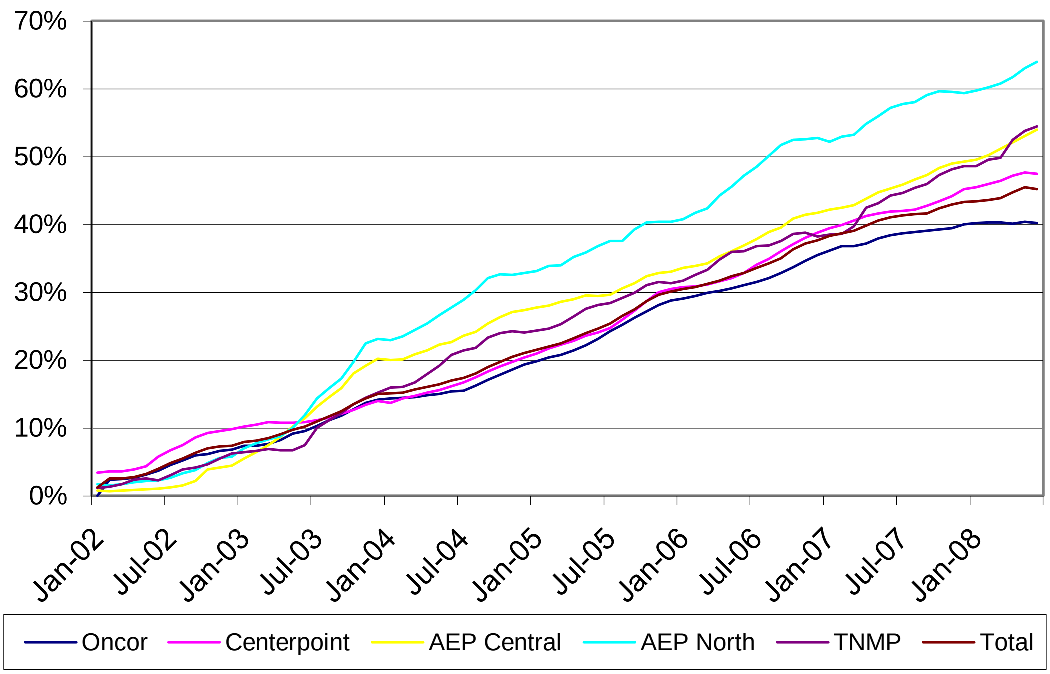


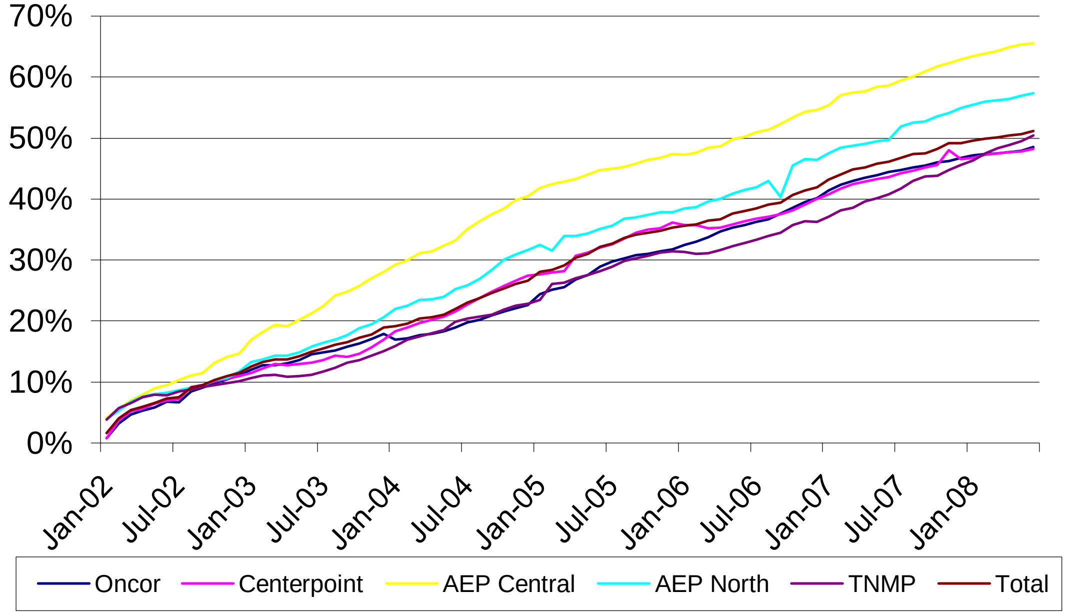
Figure 14: Residential MWh Switched to non-legacy REP by Service Territory



2. Secondary Voltage Commercial and Industrial Customers

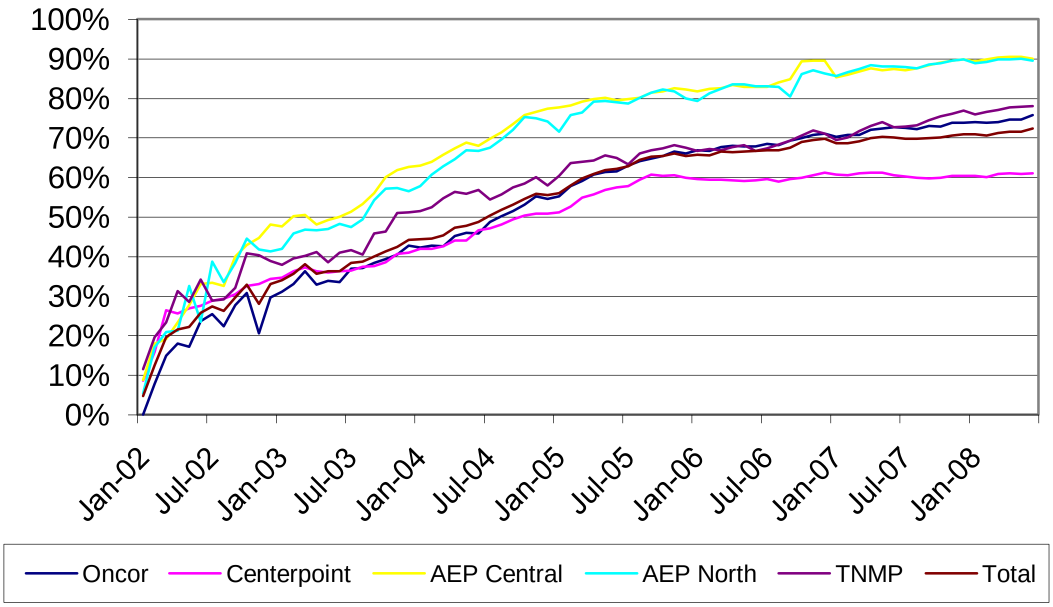
Commercial and industrial customers taking service at the secondary-voltage level have shown a greater propensity to switch than residential customers, most likely because these customers have higher energy usage, and thus higher electric bills than most residential customers. As of September 2008, 51.2 percent of commercial and industrial customers had changed providers, ranging from 48.2 percent in the CenterPoint territory to 65.5 percent in the AEP TCC service territory. These switching counts have grown more or less linearly since 2002, with some slight slowdown since 2006.

Figure 15: Secondary Voltage Customers with non-legacy REP



The largest customers in this class have a greater propensity to switch, as is shown by the fact that 72.3 percent of MWh sold to this class in June 2008 were sold by REPs other than the legacy provider.

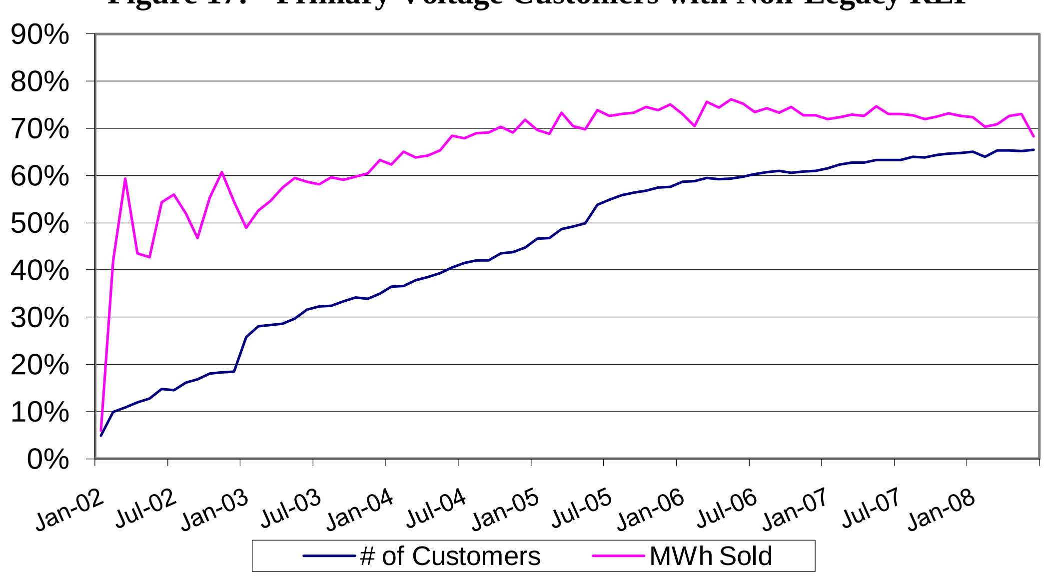
Figure 16: Non-Affiliated REP Share of Secondary Voltage MWh



3. Primary Voltage Commercial and Industrial Customers

Primary-voltage and transmission-voltage customers are large electricity consuming customers. As of June 2008, approximately 65 percent of the primary and transmission customers are with a non-legacy provider, which is an increase from about 60 percent in June 2006. The remaining 35 percent remain with the legacy provider with rates set by negotiation between those large customers and the REPs. Approximately 68 percent of MWh sold to this class were provided by REPs other than the legacy provider. This number has been roughly stable since 2004, and is down from 75 percent two years ago.

Figure 17: Primary Voltage Customers with Non-Legacy REP

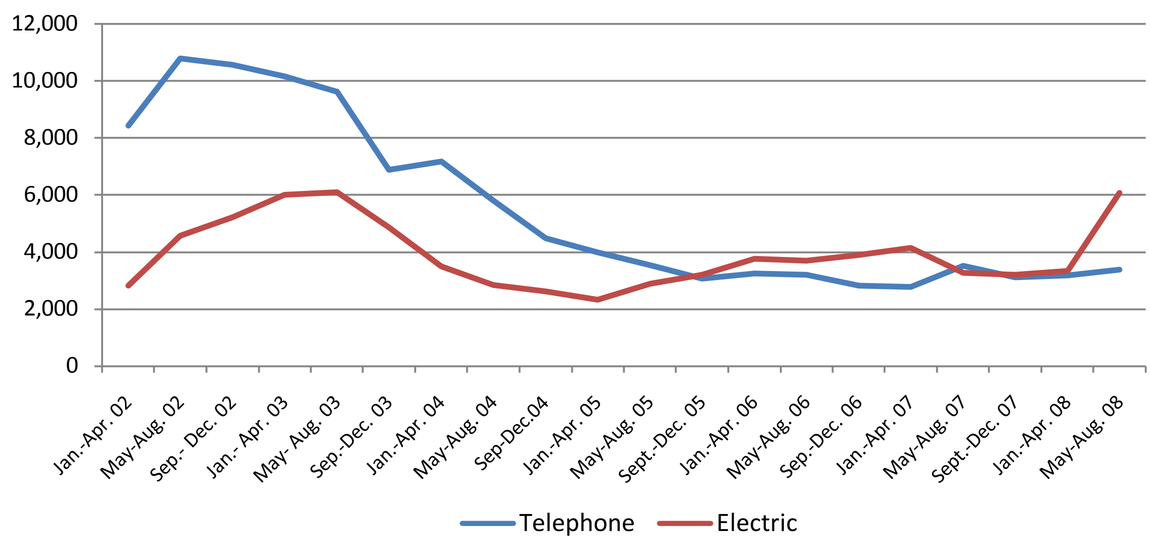


IV. Assessment of Other Senate Bill 7 Goals and Benefits

A. Customer Protection and Complaint Issues

Complaint statistics serve as a barometer for gauging company behavior and its effect on customers. The statistics also help Commission management identify company-specific trends which may lead to meetings with companies to address issues and to alert Commission Staff to the need for possible enforcement actions. In late April 2008, the Customer Protection Division (CPD) experienced a spike in the number of customer complaints. The high electricity prices coupled with some REPs leaving the market were important factors in the recent increase in the number of complaints. The increase can also be explained by increased customer awareness of the structure of the deregulated market and various REP plans and offers. Customers have exercised their option to question their bills when rate increases were implemented by REPs.

Figure 18: Total Complaints Received



Since August 2006, provision of service [70] complaints, meters complaints, and slamming [71] complaints have increased by five percent, four percent, and one percent respectively. Billing complaints and discontinuance of service complaints have decreased by eight percent and one percent respectively.

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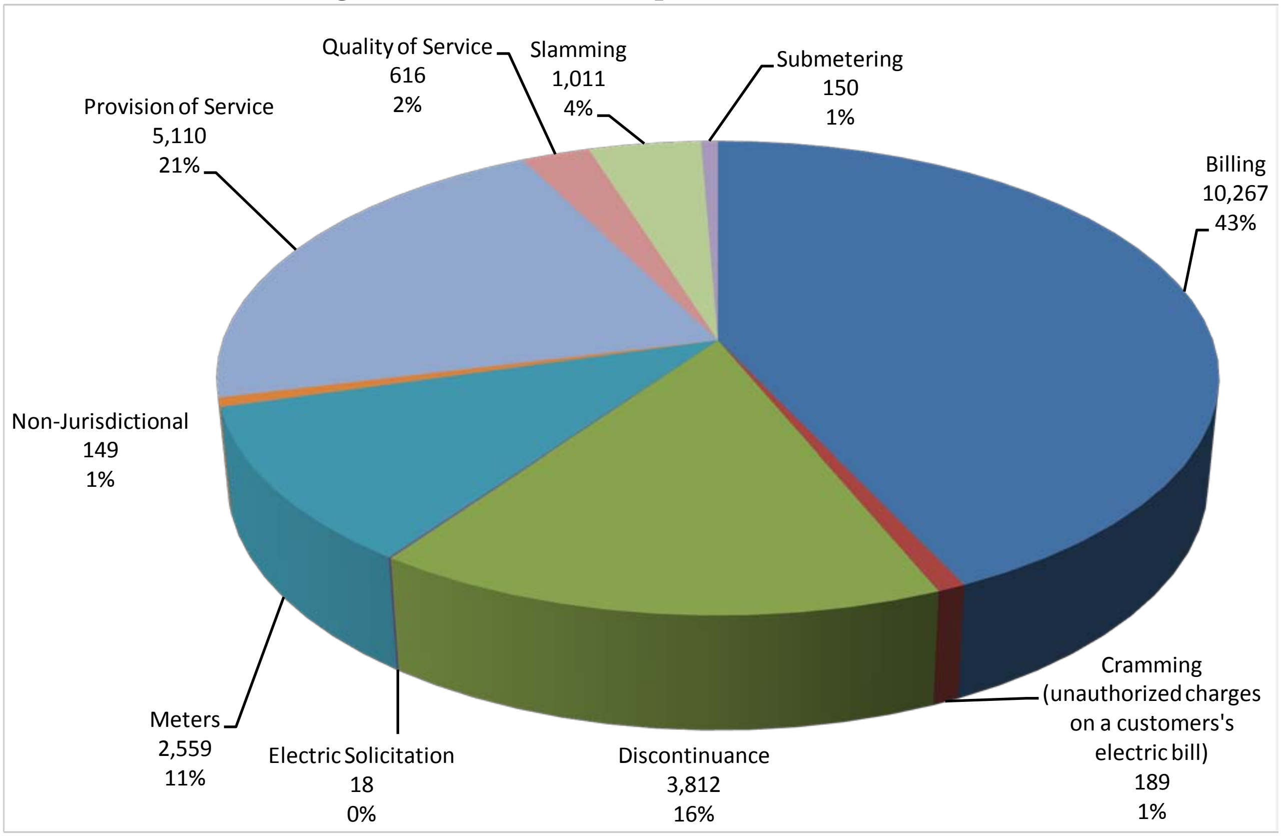
[70] Provision of service complaints consist of issues related to initiation of service, timely start-up of service, customer service, and refusal of service.

[71] When a customer's electric service has been switched to another REP without the customer's authorization.

Figure 19: Electric Complaints Received



The following issues appear to be contributing to the increase in customer complaints:

- Retail Electric Providers exiting the market with minimal notice;
- Increases in rates for customers on variable rate plans;
- The customer education campaign having made customers more aware of their rights; and
- Extreme weather conditions, dramatic changes in the price of natural gas, or events affecting infrastructure (Hurricanes Gustav and Ike).

B. Renewable Energy Mandate

Texas continues to lead the nation in renewable energy development. During the summer of 2008, the legislative goal of installing 5,880 MW of renewable capacity was reached, with over 6,000 MW of renewable capacity installed, six and a half years ahead of the date prescribed in PURA. At nearly 9,000 MW of installed wind capacity by year-end 2008, Texas has more three times the capacity of our nearest competitor, California.[72] To illustrate the scope of development in Texas, the following table

[72] US Department of Energy, http://www.windpoweringamerica.gov/wind_installed_capacity.asp#history.

compares the 2007 wind capacity in Texas and other states and nations with significant wind capacity.[73]

Table 7: Wind Capacity 2007

State or Country	Wind Capacity (MW)
Germany	**22,250**
United States	**16,820**
Spain	**15,150**
India	**7,850**
China	**5,900**
Texas	**4,360**
Denmark	**3,130**
California	**2,440**
Minnesota	**1,300**
Iowa	**1,270**

Wind accounts for about 95 percent of the state's installed renewable capacity, of which 98 percent was installed since the State implemented a renewable energy mandate with the enactment of Senate Bill 7 in 1999. Wind accounted for 92 percent of the renewable energy produced in 2007, with hydro-electric and landfill gas accounting for 3.8 percent and 3.5 percent respectively.[74] Non-wind renewable generating capacity has grown at a much slower rate than wind capacity. Nearly two-thirds of the non-wind renewable capacity is landfill gas generation. The following table shows the new non-wind capacity.

Table 8: Non-wind Renewable Capacity in Texas (megawatts)

2002	2003	2004	2005	2006	2007	December 2008
46.6	46.6	47.6	58.2	78	107.9	141.7

The energy generated from renewable resources still constitutes a small fraction of the energy consumption in the state. About 2.6 percent of the electricity generated in Texas during 2007 came from renewable energy resources, up from 2.1 percent in 2006.[75] The table below shows the growth in electricity production from renewable resources since 2002, as reported by ERCOT.[76]

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73 European Wind Energy Association, http://www.ewea.org/index.php?id=180.

74 ERCOT, https://www.texasrenewables.com/publicReports/rpt8.asp.

75 *Electric Power Monthly*, Energy Information Administration (Mar 2006, Aug 2006 and Mar 2008).

76 ERCOT reports generation from renewable resources that are registered with it to participate in the renewable energy credit program. There are some resources that are not registered, whose production is not reflected in these numbers.

Table 9: Growth in Renewable Energy Generation (MWh)

2002	2003	2004	2005	2006	2007	2008 (Jan-Sep.)
2,793,076	2,949,087	3,685,014	4,804,512	7,108,131	10,144,056	11,588,838

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 also serve as a means for authenticating renewable energy products that REPs offer their customers. In 2007, REPs retired about 3.4 million RECs to comply with the renewable energy standard and 1.6 million RECs to authenticate renewable energy products. The RECs retired for compliance purposes was roughly the same in 2005 and 2006, but the RECs that were retired to authenticate renewable energy products doubled from 2006 to 2007. As the Commission reported in its last Report on the Scope of Competition, the market value of RECs is low, with the July 2008 value reported in the $2.50 to $4.50 range.[77] For a typical residential customer using 1,200 kWh of electricity per month, the impact of the renewable energy goal was equivalent to about 9 cents per month in 2008.

The largest sellers of renewable energy to Texas customers in 2006 were Austin Energy, Reliant Energy, Green Mountain Energy, and Gexa. Together, these companies accounted for about 98 percent of the voluntary REC retirements, with Austin Energy accounting for over 80 percent of the voluntary REC retirements in 2006. A larger number of companies were active in the voluntary REC market in 2007, with TXU Energy and FP&L Energy joining the list of the companies with the largest number of voluntary retirements. In 2007, the top four companies accounted for 86 percent of the voluntary retirements of RECs.

Impact of Renewable Energy on Market Power and Residential Prices

House Bill 1090 directed the Commission to conduct a study and prepare a report on the effect that Section 39.904, Utilities Code, has had on market power and the rates paid for electricity by residential customers in this state. With the enactment of Senate Bill 7 in the 1999 Legislative Session, PURA §39.904 established a renewable portfolio standard. The standard and the development of renewable energy in the state related to the standard are discussed above. The 2015 renewable energy goal in the statute was met this summer, but renewable energy remains a small part of the Texas energy picture.

The renewable capacity that has been installed in the state has been part of a broader trend in which new generation capacity has been installed primarily by entities that did not have a large share of the generation sector in 1999. The construction of thermal and wind generation capacity have reduced the concentration in the generation sector. While renewable capacity has been an important part of this trend, the impact of thermal generation has been greater, because there has been more thermal generation than renewable generation installed since the adoption of the portfolio standard.

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[77] *Monthly Market Update*, Evolution Markets Inc. (Jul 2008), http://www.evomarkets.com.

Similarly, renewable generation has reduced wholesale and retail energy prices during some periods and has been instrumental in moderating price increases during periods in which the cost of natural gas was increasing. New thermal and renewable capacity have both been important in suppressing wholesale and retail prices in the eight years since the portfolio standard was enacted into law. Since the enactment of Senate Bill 7 in the 1999 legislative session, there have been significant additions of wind generation and gas-fired combustion turbine capacity in ERCOT. The wind generation, over the last year, has suppressed wholesale and retail electricity prices. The combustion-turbine capacity that has been added to the ERCOT generation fleet has improved the overall efficiency of the fleet in converting natural gas into electricity, and this efficiency improvement has also been instrumental in suppressing wholesale and retail prices.

Renewable energy represents a small portion of the generating capacity in ERCOT. In its May 2008 report on capacity, demand and reserves, ERCOT reported that total capacity was 72,820 MW, and the wind capacity was 5,519 MW. The wind capacity was thus about 7.6 percent of the ERCOT capacity.[78] During a period in which wind capacity increased by about 5,500 MW, about 29,000 MW of thermal capacity was added to the system, and about 9,600 MW of thermal capacity was retired or temporarily removed from service. Most of the wind and thermal capacity additions during this period were made by companies that did not have a significant share of the generation sector in ERCOT. Thus, the wind and thermal capacity additions have diluted the market share of the generating companies that had a large market share, but the impact of thermal additions was roughly five times that of wind additions.

Market power issues can be important in the context of the generating sector as a whole, or they may arise in the context of generating facilities that serve particular parts of the load, such as base load or peaking, or that are located in particular areas. For example, even if the overall market share for a company is low, if it owned a large share of the peaking supply, this concentration could result in market power issues during peak periods. Similarly, concentration in a region could result in market power issues when transmission congestion limits the effective geographic market.

Wind generation has had the impact of reducing wholesale and retail prices of electricity. Several circumstances support this conclusion. As the level of wind capacity and output have increased over the last year, there have been periods in which the wind energy being produced exceeded the capacity of the transmission system to transport the energy from west Texas to other areas of the state. This phenomenon has resulted in lower wholesale prices in the western congestion zone than in the other zones in ERCOT. It seems clear that the recent history shows that when transmission congestion results in a division of ERCOT into sub-regional markets defined by the congestion zones, the prices in the zone with the wind resources are lower than the other regions.

Prices are also lower ERCOT-wide when there are large amounts of wind energy being produced. The Independent Market Monitor prepared an analysis of the clearing prices in the balancing energy market in intervals without inter-zonal transmission congestion

[78] There was about 100 MW of non-wind renewable resources.

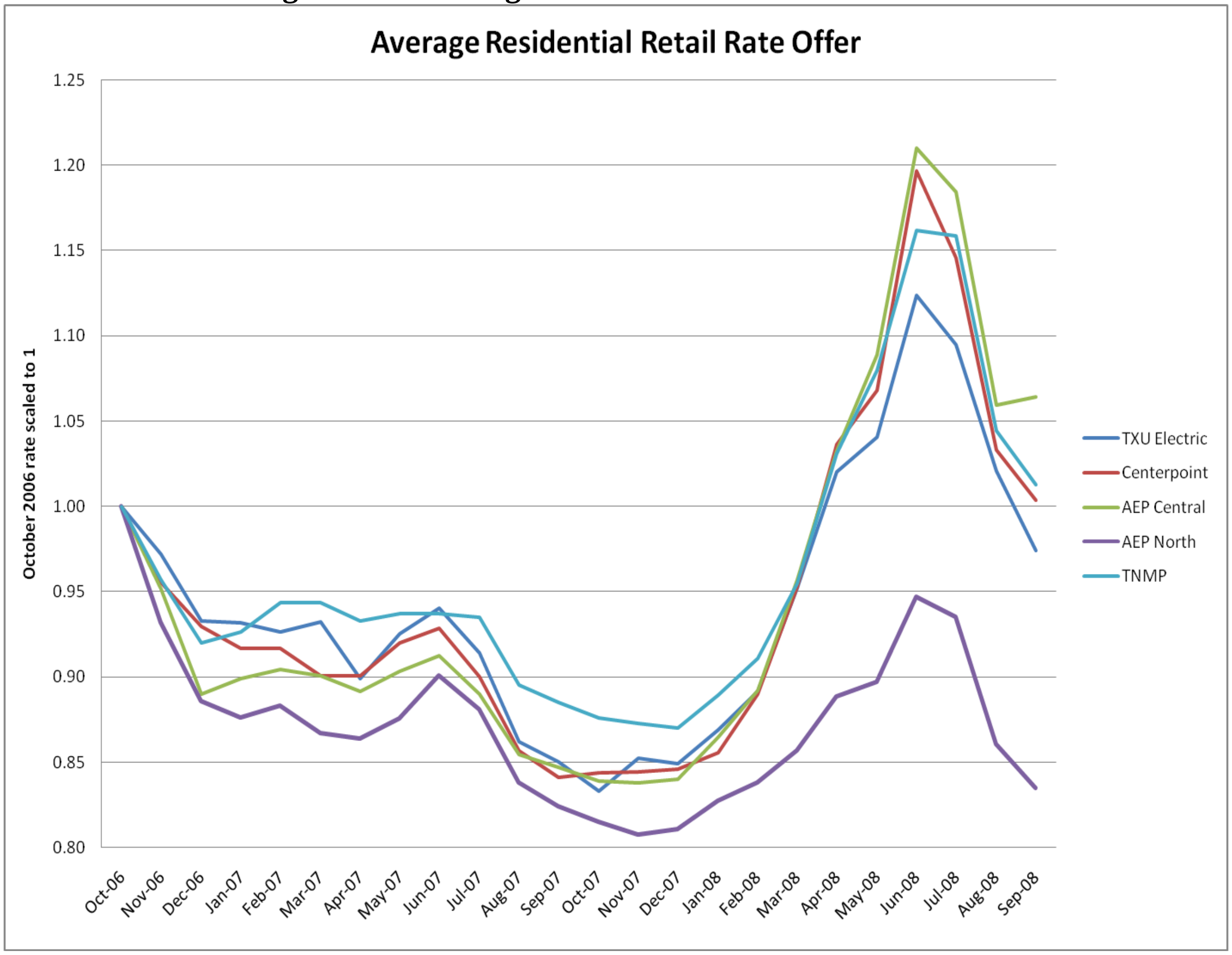
during the first ten months of 2008.[79] This analysis indicated that there is a strong statistical correlation between market clearing prices, on the one hand, and wind production, system load, and fuel prices. For each additional 1,000 MW of wind that was produced, the analysis showed that the clearing price in the balancing energy market fell by $2.38.

The regional price differences have also been reflected at the retail level, resulting in lower prices in the AEP Texas North service area than in other utility service areas. All or most of the AEP Texas North service area is in the western congestion zone. An analysis of average residential prices in the major service areas shows that the prices in the AEP Texas North service area have gone from the highest to the lowest over the past two years. In October 2006, the area with the lowest average residential price offer was TXU, with a rate of $0.1412 per kWh, and AEP North was the highest, with a rate of $0.1568. In September 2008, the area with the lowest average rate was AEP North, with a rate of $0.1309, and the area with the highest was AEP Central, with a rate of $0.1591.

The following graph shows how average residential prices have changed in the various service areas over the last two years, relative to the other service areas. The price lines are scaled to the average price in each service area in October 2006. As the graph shows, residential prices fell over the 13 months following October 2006, with the prices in most of the service areas falling by 15 percent. Prices in the AEP North service area fell by nearly 20 percent in this period. As natural gas prices began to rise during the winter of 2007-08, prices rose in all of the service areas, but they rose by a smaller amount in the AEP North service area. In most of the service areas, prices rose to a level that was 15-20 percent above the October 2006 starting price. For AEP North, prices at their peak were still five percent below the October 2006 starting price. The final month on this graph shows that prices in the service areas other than AEP North ranged from three percent below the October 2006 price to seven percent above it. In the AEP North service area, however, retail prices were 17 percent below the starting point.

[79] The analysis also excluded intervals in which non-spinning reserves were deployed by ERCOT or in which prices were higher than $250 or lower than negative $250.

Figure 20: Average Residential Retail Rate Offer



C. Energy Efficiency

To comply with House Bill 3693 enacted during the 80th Legislative Session, the Commission repealed its existing rules relating to energy efficiency and adopted a new rule.[80] The new rule raised the electric utilities' energy efficiency goals from ten percent of growth in demand to fifteen percent of growth in demand by January 2009, and to twenty percent of growth in demand by January 2010. The new rule also:

- Established an energy goal;
- Updated the cost-effectiveness standard by adjusting the avoided cost of capacity and energy;
- Granted the utilities increased flexibility in setting incentives for energy-efficiency programs, subject to the cost-effectiveness standards in the rule; and

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[80] *Amendments to* Energy *Efficiency Rules and Templates*, Project No. 33487, adopting P.U.C. SUBST. R. 25.181 (Apr. 14, 2008).

- Established a cost recovery factor to compensate a utility for reasonable expenditures on energy efficiency and a performance bonus for a utility that exceeds its goal.

The new rule was adopted in May 2008 as a direct response to House Bill 3693 with the intent to support the utilities' expansion of their energy efficiency programs. The House Bill included the higher goals for 2008 and 2009 and authority for the Commission to adopt a cost recovery mechanism and performance bonuses.

The State Energy Plan, which was completed in August 2008 and included in the report of the Governor's Competitiveness Council, identified energy efficiency as one of the five key areas essential to meet the energy demands of Texas consumers. The State Energy Plan also noted that HB 3693 requires the Commission to provide a comprehensive report on energy efficiency to the 81st Legislature, including evaluations of the potential for additional energy efficiency programs in the state, funding mechanisms, and whether the goals for reductions in peak demand growth should be increased. The State Energy Plan includes the following recommendation:

> Recommendation 24: If the PUC study indicates a greater potential for cost-effective energy efficiency reductions, the state should raise the energy efficiency goals to the higher levels contemplated under current law.[81]

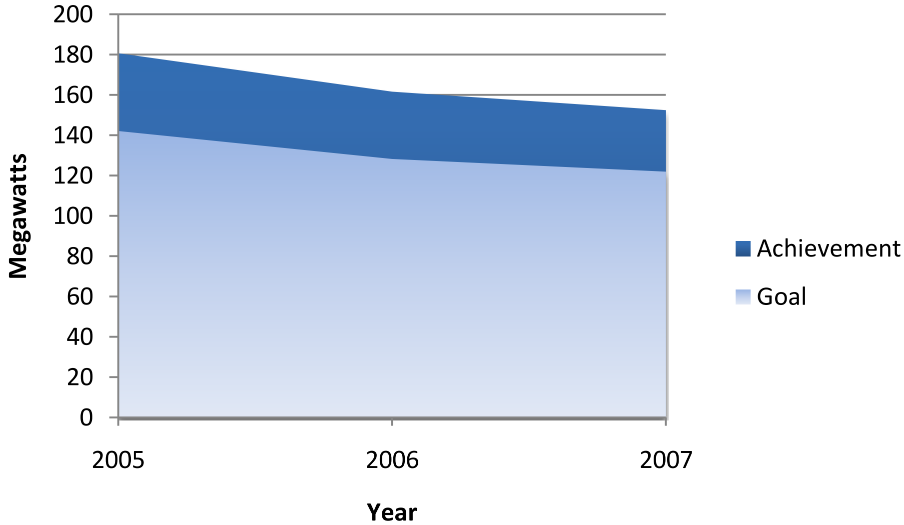
The energy-efficiency program under PURA § 39.905 is designed to improve utility customers' energy use through measures that reduce electric demand and energy consumption. This program is administered by the utilities and funded through rates. In 2007 the utilities spent approximately $73 million on this program. The goals of the PURA energy efficiency program are that:

1. Electric utilities administer energy efficiency incentive programs in a market neutral, nondiscriminatory manner;
2. All customers have a choice of and access to energy efficiency alternatives to reduce energy consumption, peak demand, or energy costs; and
3. Cost-effective energy efficiency measures are to be acquired for residential and commercial customers.

The utilities, in aggregate, have been successful in meeting the historical goal of obtaining 10 percent reductions in the growth in customers' demand. The graph below illustrates the utilities' performance in reducing growth in peak demand for calendar years 2005 through 2007.

[81] *2008 Texas State Energy Plan*, Governor's Competitiveness Council, p 9.

Figure 21: Demand Savings



During calendar year 2007, the most recent year for which results have been reported, the utilities' energy efficiency programs resulted in demand reduction that was 25 percent above the goal, with a peak demand reduction of 152 MW, compared to the aggregate goal of 122 MW. The programs saved nearly 372,000 MWh of energy. The utilities' program expenditures of $73 million in 2007 are expected to provide customers a total energy cost savings of $155 million over the ten-year life of the energy efficiency measures. The Energy Systems Laboratory at Texas A&M University has estimated that these electricity savings result in reductions of up to 1,125 tons of nitrogen-oxide emissions annually.

During FY 2008 the Commission participated in a forum to discuss a uniform reporting format for government entities that are required to report utility usage under HB 3693, and contracted for consultants to conduct an energy efficiency potential study and a study on combined heat and power. The Commission and State Energy Conservation Office hosted the forum for government officers. Approximately twenty individuals attended and provided useful information regarding their experience, their uncertainty about data needed for recording and reporting of electricity, water and natural gas consumption, and the difficulty in providing the required information on a publicly available website.

On June 5, 2008, the Commission selected Itron, Inc. to conduct a study and provide a report concerning evaluation of the potential for cost-effective energy efficiency in Texas to comply with HB 3693. The final report was delivered to the Commission in December 2008. On August 29, 2008 the Commission selected Summit Blue Consulting to conduct a study and provide a report concerning Combined Heat and Power (CHP) in Texas to comply with Section 23 of HB 3693. Summit Blue delivered a final report to the Commission in December of 2008.

V. Emerging Issues

Proposals for Streamlining Rate Regulation

During 2008, AEP Texas began a series of discussions with Commission Staff and industry stakeholders to explore ways in which the traditional rate-setting process for regulated utilities could be streamlined. The primary focus of AEP's efforts was to consider and address:

- The often significant regulatory lag currently associated with formal rate cases, that is, the lag between the time that costs are incurred and a utility can implement higher rates to recover those costs;
- The adversarial focus in a rate case on relatively few cost items;
- The length, contentiousness, and associated expenditures of time and resources in litigating formal rate proceedings; and
- Collaborative processes outside of a formal rate case that might be a more effective way to set rates.

AEP believes that the current regulatory model inhibits the timely recovery of costs and the flexibility of companies in making appropriate investments in an aging utility infrastructure.

An existing example of streamlined rate regulation that might be used for distribution service providers is the mechanism for adjusting transmission rates. Current Commission rules allow for each transmission utility in the ERCOT region, on an annual basis, to update its transmission rates to reflect changes in invested capital. If an ERCOT transmission utility elects to update its rates through this mechanism, the new rates reflect the addition and retirement of transmission facilities and also include appropriate depreciation, federal income tax and other associated taxes, the Commission-allowed rate of return, and changes in loads. Such updates of transmission rates are subject to reconciliation at the utility's next complete transmission cost-of-service review, in which the Commission reviews whether the cost of transmission plant additions were reasonable and necessary and, additionally, whether there was any over-recovery of costs.

In late 2007, for areas outside of ERCOT, the Commission adopted an analogous rule for streamlined recovery of transmission costs.[82] No similar provision exists, however, for capital additions related to distribution facilities, whether inside or outside the ERCOT region. AEP has suggested four options that could be considered as a framework for streamlining the traditional rate-setting process without diminishing current regulatory oversight. These four options include:

[82] This rule was adopted pursuant to HB 898, enacted in the 79th Legislative Session.

- **A Distribution Cost of Service (DCOS)** would be patterned after the existing transmission cost recovery mechanism, and would allow annual recovery of and return on net incremental distribution-plant capital expenditures and associated tax effects. Capital investments added to rate base through the DCOS mechanism would be subject to review in full base-rate cases, with a maximum time period of five years between such proceedings.

- **A DCOS mechanism, including O&M** would be implemented in the same general manner as described above, with additional recovery of certain operation-and-maintenance (O&M) expenses.

- **A Targeted Programs** option would allow a utility to file for preapproval of specific (targeted) capital and O&M expenditures designed to enhance the existing distribution infrastructure; examples might include programs to enhance reliability, such as tree-trimming programs or infrastructure-hardening programs. Annual reporting requirements would ensure that the utility is complying with predetermined criteria, and revenue recovery would be achieved through a separate surcharge or an annual DCOS mechanism.

- **Formula Rate Plans** would allow a utility to make annual filings and adjust revenues to a predetermined return-on-equity level; such a program would be initiated for a specified period of time (for example, three years), and then reviewed to determine whether it should continue.

One problem regarding such proposals to streamline certain aspects of the regulatory process is that some degree of uncertainty exists with respect to the extent of Commission authority for implementation of such a plan. At this time, the Commission has not expressly considered or made a determination on this issue.

VI. Legislative Recommendations

A. Procedural Recommendations

1. Oversight Confidentiality

As stated in the 2007 Scope of Competition in Electric Markets report, the Commission believes that the enforcement of Texas statutes and Commission rules leads to the critical compliance that ensures a well-functioning marketplace. To help ensure compliance, the Commission has expended significant resources to enhance its investigations and prosecutions in the telecommunications and electric markets in Texas. In October of 2007 the Commission created a new division, the Oversight and Enforcement Division, to handle all enforcement duties. The Commission also retained an Independent Market Monitor (IMM) for the ERCOT wholesale electric market, pursuant to the requirements of PURA §39.1515. The IMM monitors the wholesale electric market and investigates possible instances of market manipulation or violation of certain Commission or ERCOT rules. In addition, the Commission works closely with the Texas Regional Entity (TRE), a functionally independent division of ERCOT, which has been authorized by the Commission to investigate compliance with ERCOT protocols and operating guides.

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 could unfairly impugn the business practices of telecommunications or electric providers before all the facts have been determined.

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 provide that the investigation files of those agencies are confidential as a matter of law. Some of the state agencies that are provided with this protection during the investigatory phases of their prosecutions include the State Securities Board, the Health and Human Services Commission, the Texas Department of Health, the Texas State Board of Veterinary Medical Examiners, the Texas State Board of Acupuncture Examiners, and the Texas Board of Chiropractic Examiners.

The Commission believes it would be sound public policy and would enhance confidence in the telecommunications and electric markets for the Legislature to make the investigation records of the Commission, the IMM, and the TRE confidential as a matter of law.

2. Enforcement Authority and Other Powers

Two issues have emerged that may warrant granting the Commission additional procedural powers. These powers would include: (a) the authority to order an entity found to have violated a statute or rule to make restitution to the market, market participants, or other parties injured by the violation, and (b) the authority to provide informal guidance on regulatory issues.

The Commission has the authority to issue administrative penalties for violations of statute or Commission rules.[83] It also has the authority to adjudicate consumer complaints relating to basic customer protections, which includes the authority to require a utility or REP to make a customer whole for fraudulent or misleading practices or charging a rate that is different from the rate in a Commission-approved tariff.[84] The Commission has concluded, however, that it does not have broad authority to require restitution for injuries to participants in the wholesale electricity market.[85] The ability of a party that has been injured by the conduct of another participant in the wholesale market to obtain effective relief has been confounded by a decision of a federal court that limits the ability of a market participant to obtain redress under the anti-trust laws.[86] The basis for this decision was the court's view that the Commission was the appropriate venue for redressing economic injuries incurred through participation in the wholesale market. Thus, the Commission believes that the Legislature should consider authorizing the Commission to order violators to make restitution or pay restoration damages for economic injuries incurred by their violation of statutes or Commission rules in addition to any administrative penalty that may be assessed.

Many regulatory agencies have the authority to issue informal guidance to the persons that they regulate, particularly with respect to outlining whether a particular course of conduct would, in the agency's view, be consistent with the laws and regulations that the agency administers. The issuance of an advisory opinion can provide valuable advice to a company before making investments or conducting operations that might be questionable under state law. The legislature may wish to consider granting the Commission the authority to issue advisory opinions. In the electricity business, providing clarification to a company concerning issues such as the purchase of assets or the acquisition of another company could provide valuable advice and permit it to avoid expensive regulatory proceedings, without impairing the Commission's authority.

The following agencies have explicit statutory authority to issue advisory opinions:

- Texas Ethics Commission;[87]

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[83] PURA § 15.023.

[84] PURA § 17.004, 36.002.

[85] *Notices of Violation by TXU Corp., et al., of PURA Section 39.157(a) and P.U.C.* SUBST. R. *25.503(g)(7),* Docket No. 34061, Order at 8 (Dec. 22, 2008) ("The Commission does not have statutory authority to order that a refund be paid to ERCOT for a market participant's violation of PURA section 39.157(a) and P.U.C. SUBST. R. 25.503(g)(7)"). *See also Notices of Violation by TXU Corp., et al., of PURA Section 39.157(a) and P.U.C.* SUBST. R. *25.503(g)(7),* Docket No. 34061, Preliminary Order at 2-6 (June 27, 2007).

[86] *Texas Commercial Energy, LLC v. TXU Energy,* Inc. 413 F.3d 503 (5th Cir. 2005), cert denied 546 U.S. 1091 (2006).

[87] Government Code § 571.091.

- A sports and community venue district;[88]
- Texas Medical Board;[89]
- State Board of Dental Examiners;[90]
- Texas Board of Nursing;[91]
- Texas Board of Professional Engineers;[92] and
- Texas Lottery Commission.[93]

B. Substantive Recommendations

1. Additional Oversight of ERCOT

The Commission recommends several changes to the provisions of PURA concerning the governance of ERCOT, to enhance its oversight of the organization.

The provisions of law concerning the governance of ERCOT have included the Chairman of the Commission as a non-voting member of the board of directors. In recent years, all of the Commissioners have attended meetings of the board to maintain current knowledge of ERCOT's activities and direction and provide their views on important market and management issues that the board is responsible for. The Chairman, as a member of the board, is able to attend both the public sessions and the executive (closed) sessions of the board. The other Commissioners have not been able to attend executive sessions, and the Commission believes that it would be appropriate to make the Commissioners non-voting members of the board, so that they may attend executive sessions.

One of the important functions of the board of directors is to approve financial policies and the incurrence of debt. While the Commission approves the fees that permit ERCOT to recover its costs of operating, current law does not require the Commission's approval for ERCOT to incur debt. Without this authority, it is possible that ERCOT could incur additional debt that might require a higher fee, in order to pay the principal and interest on the debt as they come due. The Commission believes that requiring Commission approval prior to the incurrence of debt would facilitate the Commission's control over ERCOT's financial situation and greater ability to avoid increases in the ERCOT fee.

[88] Government Code § 335.109.

[89] Occupations Code § 162.107.

[90] Occupations Code § 258.157.

[91] Occupations Code § 301.607.

[92] Occupations Code § 1001.601.

[93] Occupations Code § 2001.059.

ERCOT is a not-for-profit organization, but it is recognized for federal income tax purposes as a non-profit organization under section 501(c)(4) of the Internal Revenue Code. This status does not give it the ability to borrow using bonds whose interest is exempt from federal income taxes. Other organizations that perform most of the same functions as ERCOT in electricity markets are non-profit organizations under section 501(c)(3) of the Internal Revenue Code and have the ability to issue tax-exempt bonds. This ability results in a lower cost of capital for the organization. The existing provisions of PURA concerning the membership of the board of directors may be an impediment to obtaining 501(c)(3) status for ERCOT. The Commission recommends that the benefits of 501(c)(3) status be quantified and, if warranted, that consideration be given to modifying membership provisions to make it more feasible for ERCOT to obtain 501(c)(3) status from the Internal Revenue Service.

2. Advanced Metering

The Commission made several recommendations in its Report to the Legislature on Advanced Metering as required by HB 2129. In response to the statutory directive to identify necessary changes to Texas policy to remove barriers to the use of advanced metering and metering information networks or other advanced transmission and distribution technologies, the Commission offers the following recommendations for consideration by the Texas Legislature:

- The Governor's Competitiveness Council in its Texas State Energy Plan recommended that the Commission have the authority to order utilities to deploy advanced meters. The Legislature should clarify that the Commission has the authority to order utilities to deploy advanced meters, as rapidly as possible,[94] with the appropriate cost recovery provided under the Commission's advanced metering rule.
- The Legislature should clarify whether the 2005 legislation relating to advanced meters, PURA § 39.107, applies to utilities outside of ERCOT.[95]
- State policy should also ensure that all retail customers have the option to have their billing determined on actual interval data captured from the advanced meters, so they receive the full benefits of changes in consumption behavior.
- State policy should continue to recognize that the retail electric market will benefit from knowledgeable residential electric customers making informed purchasing decisions to meet their energy needs.

[94] *See 2008 State Energy Plan* adopted by the Governor's Competitiveness Energy Council, Recommendation 22 which states, "The state should require TDUs to deploy advanced meters, with an appropriate cost recovery mechanism to ensure that TDUs earn a reasonable return on this investment. The PUC should have the authority to require deployment of advanced meters as rapidly as possible."

[95] *See* P.U.C. SUBST. R. 25.130(b), which states, "This section is applicable to all electric utilities, including transmission and distribution utilities, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) § 39.452(d)(1), is not subject to PURA § 39.107; and to the Electric Reliability Council of Texas (ERCOT).

3. Repeal of Rules on Gas-Fired Plants

The Legislature should repeal the resumption in PURA in favor of gas-fired plants in order to ensure that a diverse mix of resources is developed in Texas. Natural gas has gone from being an abundant fuel that the Legislature promoted as a fuel for electric generation to a scarce fuel with significant price volatility, and its promotion as a generation fuel is likely no longer appropriate.

Hurricanes Katrina, Rita, and Ike 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 opportunities to recover natural gas from shales in Texas, such as the Barnett shale, 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.

The Commission, joining with the Governor,[96] 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

96 *2008 Texas State Energy Plan*, Competitiveness Council, Office of the Governor; Recommendation 2: Repeal of Gas-Fired Plants Order.

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.

4. Nuclear Decommissioning

House Bill 1386 enacted during the 80th Legislative Session requires the Commission, in conjunction with the Nuclear Regulatory Commission (NRC), to investigate and file legislative recommendations regarding the development of “a mechanism whereby the State of Texas could ensure that funds for decommissioning will be obtained when necessary in the same manner as if the State of Texas were the licensee under federal law.”[97] In response to this directive, the Commission offers the following recommendations.

Based on discussions with the staff of the NRC, the Commission understands that NRC regulations do not permit recognition of the State of Texas as a licensee unless the State assumes all licensee obligations, as owner or operator or both, through the NRC’s formal licensing process. That is, the NRC will not consider the State as a licensee only for purposes of decommissioning funding. The State may, however, use its capabilities to

[97] Public Utility Regulatory Act, TEX. UTIL. Code ANN. § 39.206(q) (Vernon 2007 & Supp. 2008).

access financial resources to provide assurance that decommissioning funds will be available when needed. In that case, the NRC would consider financial commitments made by the State to the licensee in assessing whether a potential licensee has complied with the NRC's financial assurance requirements for decommissioning funding. The Commission has identified three mechanisms whereby the State of Texas could provide such financial assurance: prepayment, an external sinking fund, and a guarantee agreement.

First, the State of Texas could prepay the full amount required for decommissioning. Under this option, the Legislature would establish a trust or other protected account in accordance with NRC regulations[98] and deposit into that account funds sufficient to satisfy the decommissioning obligations for each nuclear power reactor licensed by the NRC for construction in Texas.[99] In the event that a licensee's sinking trust fund and other methods of financial assurance fail to satisfy the licensee's decommissioning obligations, the prepaid funds would be available to ensure decommissioning of the reactor.

Under the prepayment option, the Legislature would need to deposit additional funds into the account each time that a new nuclear power reactor is licensed by the NRC for construction in Texas. Article VIII, section 6 of the Texas Constitution provides that no appropriation of money shall "be made for a longer term than two years." In order to prepay nuclear decommissioning funds for future reactors, therefore, the Legislature would either need to (i) pass additional appropriations legislation each time the NRC licenses a nuclear power reactor for construction in Texas, or (ii) secure an amendment to the Texas Constitution allowing the Texas Legislature to appropriate money for nuclear decommissioning for a term longer than two years. Furthermore, Article III, section 51 of the Texas Constitution provides that "[t]he Legislature shall have no power to make any grant or authorize the making of any grant of public moneys to any individual, association of individuals, municipal or other corporations whatsoever." If the Texas Legislature determines that the prepayment of decommissioning funding obligations violates this provision, the Legislature would need to secure a constitutional amendment specifically authorizing such a program.[100]

Second, the Texas Legislature could deposit funds periodically into an external sinking fund in accordance with NRC regulations.[101] The constitutional considerations noted above with respect to prepayment would likely also apply to this option.

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[98] 10 C.F.R. § 50.75(e)(1)(i). *See also* 10 C.F.R. § 50.75(h) (containing, *inter alia*, restrictions on withdrawal of funds from a decommissioning trust fund for purposes other than decommissioning and ordinary administrative costs).

[99] NRC regulations permit a licensee in certain circumstances to take credit for projected earnings on the prepaid decommissioning funds. *Id.*

[100] See, e.g., Tex. Const. art. III, § 51-a.

[101] 10 C.F.R. § 50.75(e)(1)(ii). *See also* 10 C.F.R. § 50.75(h) (regarding restrictions on withdrawals from sinking funds).

Third, the Texas Legislature could establish the State of Texas as a guarantor of the licensees' decommissioning funding obligations. NRC regulations describe the required terms for such a guarantee.[102] Article III, section 50 of the Texas Constitution provides that "[t]he Legislature shall have no power to give or to lend, or to authorize the giving or lending, of the credit of the State in aid of, or to any person, association or corporation, whether municipal or other, or to pledge the credit of the State in any manner whatsoever, for the payment of the liabilities, present or prospective, of any individual, association of individuals, municipal or other corporation whatsoever." If the Texas Legislature determines that a guarantee of decommissioning funding obligations violates this provision, the Legislature would need to secure a constitutional amendment specifically authorizing such a program.[103]

5. Energy Storage Innovation Prizes

The Commission shares the view of the Governor's Competitiveness Council that the state should create innovation prizes with private-public revenue aimed at the commercialization of large-scale energy storage. Energy storage technology has several potential uses in an electric system, including meeting peak demand with less generating capacity and enhancing the role of intermittent resources, such as wind energy. Because of the intermittent nature of wind energy, fossil fuel units must be kept in reserve to meet customers' needs in the event of a drop in production of wind energy. Large-scale energy storage technologies have the potential to offset changes in wind energy production, rather than relying on thermal generation units for this purpose. Storage devices could also permit wind energy to be delivered to customers with a lower level of investment in transmission and allow wind energy to be stored and delivered when electrical demand is high. Compressed air storage and large-scale battery facilities show promise but are not yet commercially viable. Innovation prizes to help these technologies mature should be pursued.

6. Solar Generation Sales Tax Exemption

Texas, a state with one of the best solar resource bases in the country, should continue to support both thermal and photovoltaic solar energy technologies as they mature. For example, in April 2008, Governor Perry announced that Texas would invest $1 million through the Texas Enterprise Fund in Heliovolt Corporation of Austin for a manufacturing facility to produce the company's thin file solar power cells. Consistent with the recommendation in the State Energy Plan, the state should adopt a sales tax exemption for the purchase and installation of solar generation systems by residential and commercial customers.

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[102] 10 C.F.R. § 50.75(e)(1)(iii).

[103] See, e.g., Tex. Const. art. III, § 50a.

7. Clean Coal Technology Innovation Prize and Sales Tax Exemption

Carbon capture and storage (CCS) is a technology to capture and store the carbon-dioxide emissions of power plants. This is an emerging technology with large and uncertain development costs. As the Governor's State Energy Plan states, if demonstration projects are successful, CCS could prove beneficial for Texas because it could sustain the demand for Texas lignite and help in enhanced oil recovery. Consistent with the recommendation in the State Energy Plan, it may be appropriate to aid private industry efforts to implement large-scale CCS. Two measures that the state could undertake currently are an innovation prize for the large-scale deployment of a mine-mouth clean-coal generating facility that uses Texas lignite as its primary fuel and captures nearly all carbon emission for storage underground or use in enhanced oil recovery or other market driven beneficial use.[104] In addition, a five-year sales tax exemption for equipment used to capture and store carbon dioxide for facilities using Texas lignite as a fuel source would reduce the costs and risks of developing CCS projects.

8. Energy Efficiency Goals

House Bill 3693 directed the Commission to conduct a study of the ability of electric utilities to meet higher energy efficiency goals. Specifically, the legislation posed the question whether the utilities could meet a goal of meeting 30% of the growth in electricity demand by the end of 2010 and 50% of the growth in electricity demand by the end of 2015 through energy efficiency. The State Energy Plan recommended that legislation be enacted to adopt these goals if the study concluded that these goals could be met. The Commission hired Itron Inc. to perform this study, and its report concludes that these goals are achievable. Accordingly, the Commission recommends that the energy efficiency goals in PURA § 39.905 be amended to include meeting 30% of the growth in electricity demand by the end of 2010 and 50% of the growth in electricity demand by the end of 2015 through energy efficiency.

9. Customer Education

In 1999, the Commission was appropriated $12 million per year from the System Benefit Fund to conduct a statewide education campaign to inform Texans about changes in the electricity market. Subsequently, the education campaign was funded at much lower levels. The education program has been funded at $750,000 per fiscal year for the past six years, which is primarily used to fund a customer-education web site, a contact call center and minimal outreach. As the competitive market matures and as new features like advanced metering are added, the Commission believes it is important to expand the original "shop, switch, save" message to include information about energy conservation and efficiency, renewable energy and advanced metering as part of the Commission's customer education effort. To reach the more than five million customers in ERCOT, the Commission will need significantly more funding to create and disseminate information for the public on these topics. The Commission requests that the state increase the funding for its education campaigns.

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[104] *2008 Texas State Energy Plan*, Competitiveness Council, Office of the Governor; p 45.

10. Enhancement of Opportunities for Distributed Renewable Generation

In the 2007 session of the Legislature, two new sections were added to PURA to address issues related to distributed renewable generation (DRG), including solar generation. It appears that the Legislature expected that these new sections would foster additional renewable capacity that would be installed at customers' homes and businesses, including solar generation on the buildings of school districts. In considering rules related to DRG, the Commission concluded that there remain several obstacles to installation of DRG. These include a requirement that the owner of a generation facility, even a small generation facility at a customer's home or business, register as a power generation company. Also, it is difficult for a third party (other than the customer) to own DRG that is located at a customer's home or business. Ownership of the DRG by a third party could provide economies of scale or tax benefits to the third-party owner of the DRG that would not be available to the customer, so that there are advantages to third-party ownership. The Commission believes that it is appropriate to amend PURA to address these obstacles.

In the new sections enacted during the 2007 session, a customer that owns DRG may sell any energy that is excess to the customer's needs to a retail electric provider, if the customer is in an area that is open to retail competition. The new sections, PURA §§ 39.914 and 39.916 require the owner of DRG to sell any excess energy, if he chooses to sell the energy, to the REP that is providing electric service to the home or business where the DRG is located. Under these sections, however, the REP has no obligation to buy the excess energy from the DRG facility. If the Legislature intends to provide additional opportunities for DRG, it may want to clarify these new sections, establishing that the REP has an obligation to buy excess energy from the owner of the DRG facility and establish a pricing principle for these sales, such as the REP's avoided cost (the cost to the REP of acquiring energy from its customers from another source).

11. Provider of Last Resort

Under the current rules for the Provider of Last Resort (POLR), a REP's inability to meet its obligations or collateral requirements with ERCOT can trigger the transfer of the customers to POLRs. When this occurred in late May of 2008, prices in the wholesale market were high, and many of the customers who were transferred from the REP they had chosen to the POLR experienced rates with the POLR REP that were much higher than their prior rates. The Commission's formula for POLR rates is based on the costs that the POLR will face in the wholesale market when it acquires the POLR customers and risks of serving these customers, such as the risk that new customers will not pay their bills when they come due.

Many of the customers who were transferred to POLR REPs in 2008 were angry at being transferred, at losing an advantageous rate, and at being offered POLR service at a much higher rate. (Most of the POLR REPs offered the customers rates that were lower than what would have resulted from the application of the POLR rate formula, but higher than what the customers had been paying.) Many of these customers switched to other REPs and failed to pay the POLR REP for the energy that they received while on POLR service.

The Commission is considering amendments to two rules that have a significant impact on the transfer of customers to POLR service, the REP certification rule and the POLR rule. The objective of the changes in the REP certification rule is to establish higher financial and managerial expertise standards for REPs. These amendments, if adopted, should make it less likely that a REP will encounter financial difficulties and that its customers would be transferred to POLR service. The Commission is also considering amendments to the POLR rule that could include different pricing methods for POLR service.

One of the ideas that has emerged in discussions concerning changes to the POLR rule is to establish an insurance pool that would permit the terms of POLR service to be more advantageous to customers, while spreading the risks of doing so more broadly. Such an insurance pool might, for example, permit POLR REPs to offer customers a lower rate for a short period while the customers are shopping for a market rate. The insurance pool could compensate POLR REPs for any losses associated with providing service to customers at a rate that is below their costs of serving the customers and losses related to non-payment by the POLR customers. It is not clear whether the Commission has the authority to adopt and require the funding of such a risk pool arrangement, and the Legislature may want to consider permitting POLR service to be partially funded from a source other than POLR REPs.

12. Securitization of Storm Repair Costs

Current law allows allow for the securitization of stranded costs, regulatory assets and certain other costs that were determined in the proceedings to true-up stranded costs.[105] In addition, in the 2007 session, the legislature enacted new sections that permitted storm repair costs associated with Hurricane Rita to be securitized.[106] In the 2009 Legislative Session the utilities that were affected by Hurricanes Gustav and Ike, Entergy and CenterPoint, are expected to propose legislation that would allow them to securitize storm repair costs, subject to Commission approval. Because of the likelihood that future tropical storms, hurricanes and other major weather events could result in significant damage to electric facilities operated by Texas utilities and the financial benefits of securitization, the Legislature may want to consider permanent legislation that would permit utilities to use securitization as a means of financing storm repair costs. This type of financing lowers the carrying costs associated with the recovery of hurricane reconstruction costs relative to the costs that would be incurred using conventional financing methods.

[105] PURA §§ 39.262 and 39.301.

[106] PURA §§ 39.458-.463.

Appendix: Acronyms

AEP	American Electric Power
AEP TCC	AEP Texas Central Company
AEP TNC	AEP Texas North Company
AMI	advanced metering infrastructure
AREP	affiliated retail electric provider
BES	Balancing Energy Service
BPL	Broadband over Powerline
CCN	Certificate of Convenience and Necessity
CenterPoint	CenterPoint Energy Houston Electric, LLC
CPL	CPL Retail Energy
CREZ	competitive renewable energy zone
CTC	competition transition charge
DRG	distributed renewable generation
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
IMM	Independent Market Monitor
IPP	independent power producer
kWh	kilowatt-hour
LNG	liquefied natural gas
MCPE	Market Clearing Price of Energy
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
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
TRE	Texas Regional Entity
TNMP	Texas-New Mexico Power Company
TPIA	Texas Public Information Act
TSP	transmission service provider
WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council