III. Effects of Competition on Rates and Service

In the last two years, consumers in every competitive area of the Texas retail electric market have enjoyed an enviable position with variable and one-year fixed rates that are up to three cents per kWh below the national average. Average all-in wholesale prices for electricity in ERCOT were $35.09 per MWh in 2009 and $43.02 MWh in 2010, compared to $78 per MWh in 2008. In comparison, in 2009 all-in prices for electricity were $38 per MWh in the California electricity market, $55 per MWh in the New York market, $50 per MWh in PJM, and $59 per MWh in the New England market.

Electricity rates in Texas are greatly affected by natural gas prices as gas is burned to generate about 42% of electricity (2009), with an even higher percentage during periods when electricity demand is high. In the last two years natural gas prices have fallen from a 2008 peak of about $13 per MMBtu. With gas prices averaging $4.50 per MMBtu this year, the most competitive offers in the Texas power market are below the 2001 levels prior to the introduction of retail competition. The most competitive offers in the Texas power market have decreased an average of 13.1% for fixed rates and 17.5% for variable rates, not adjusted for inflation, since the state opened its market to retail competition in 2002.

Electricity in the competitive retail market is also a bargain relative to the cost of natural gas. When Texas deregulated retail electric sales, the "Price-to-Beat" for incumbent REPs was based on the NYMEX Natural Gas Futures 12-Month Strip prices. This 12-Month Strip price reflects what the market is paying for a supply of natural gas to be delivered over the next 12 months. When the Price to Beat for the incumbent REPs was set in late 2001, prices of the 12-Month Natural Gas Strip was $3.11 per MMBtu. The average of the 12-Month Strip prices for the first ten months of 2010 was $5.12 per MMBtu. Thus, one-year fixed products are 13% below the Price to Beat set for the opening of competition in 2002.

New REPs have continued to enter the market, selling plans with an array of terms of service, from one month to multiple years, up to 100% renewable energy, fixed rates, indexed rates and variable rates. In the residential sector, most retail customers may choose from over 35 REPs offering as many as 226 different rate packages. ERCOT reports that 26 new REPs entered the market in 2009. Residential customers have about 2.5 times more options in service plans than they did at the end of 2008.

As of June 2010, over 3.4 million individual customer premises were taking service from REPs other than the incumbent provider in their area, based on data reported to the Commission by the Transmission and Distribution Utilities (TDUs). This accounts for more than 52% of all customers in service areas open to competition. Of these customers, 83.7%, or approximately 2.9 million, are residential customers.

The highest rate of switching is in the TNMP service area, at 66.89%, and the lowest rate is in the Oncor service area, at 45.86%. Having achieved the switching rate of 50% in January 2010, Texas is the only state with retail competition where more than half of residential customers have chosen to be served by non-incumbent providers. This is further evidence that the state's well-structured competitive market is promoting competition among market participants to the economic benefit of customers. 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 competitive REPs marketing throughout ERCOT.

A. Effect of Competition on Rates

1. Wholesale Market Prices

There are three major components to the ERCOT wholesale market:

1) The bilateral market, which compromises 90% to 95% of all power traded;

2) The balancing energy market, which makes up the other 5% to 10% of energy bought and sold and is used by ERCOT to match supply and demand in the short term, and;

3) The ancillary service markets, which are used by ERCOT to procure capacity to maintain system reliability.

In general, Texas wholesale power prices tend to follow natural gas prices since 70% of the generation is fueled by natural gas. As a result, natural gas-fueled generation typically sets the market price for energy in the balancing energy market. Although most power is purchased through bilateral forward contracts, prices in the balancing energy market are highly visible and influence prices in bilateral markets.

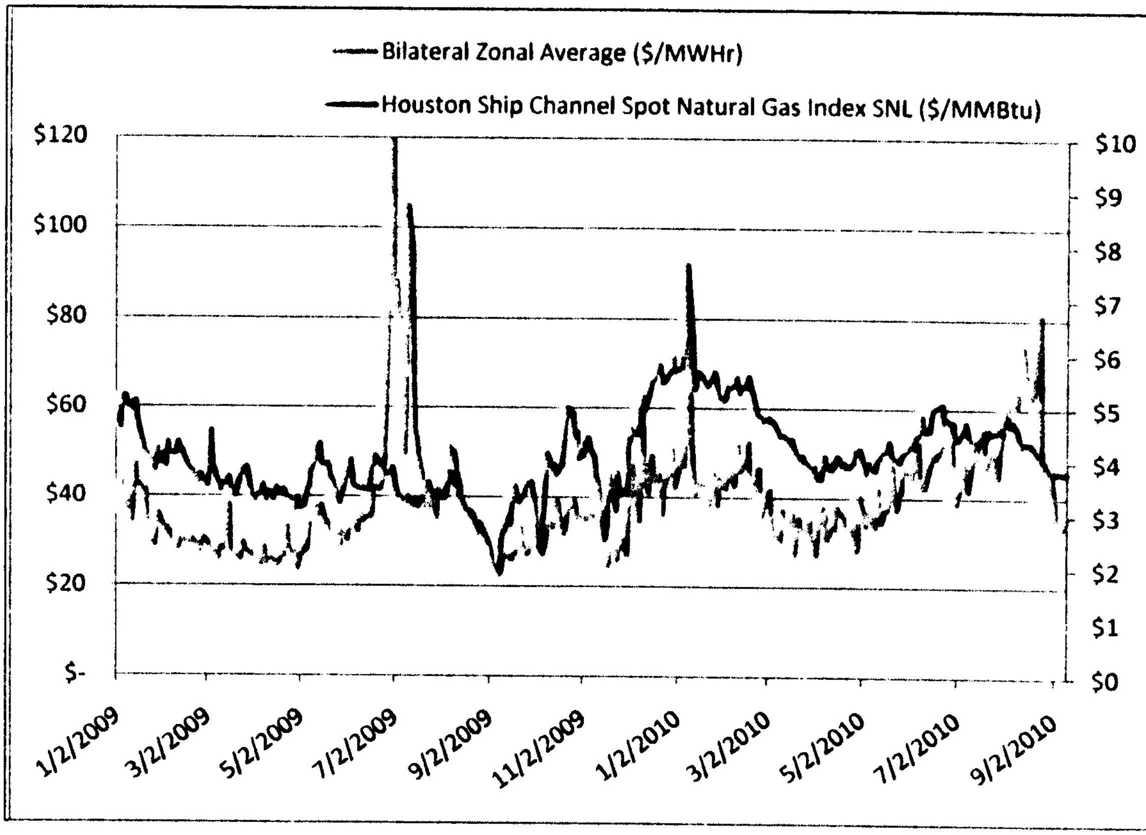
a. Balancing Energy, Bilateral, and Gas Prices

Natural gas prices in 2009 were the lowest they have been since 2003, averaging \$3.74 per MMBtu, compared to \$8.50 per MMBtu in 2008. Gas prices edged higher in the first 9 months of 2010, averaging \$4.54 per MMBtu through September 2010. Average bilateral wholesale prices were \$38.18 in 2009 and \$44.17 in the first three quarters of 2010,[75] reflecting the higher 2010 natural gas prices.

The ERCOT market relies on bilateral contracts between buyers and sellers of electricity as the principal mechanism for trading power. While bilateral agreements are negotiated in private, reporting agencies like SNL Financial compile daily wholesale market prices that are generally indicative of bilateral contract prices. Figure 1 shows that bilateral wholesale electricity prices and natural gas prices follow the same general trend.

[75] SNL Financial

Figure 2 - Bilateral Electricity Prices and Natural Gas Prices



b. Balancing Energy Market Prices

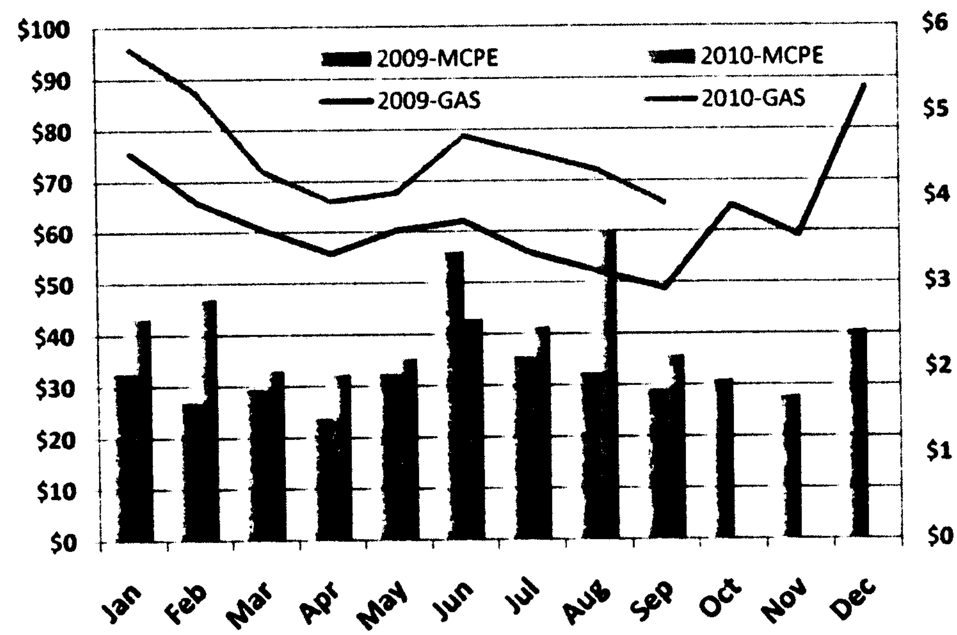
ERCOT procures and deploys balancing energy to maintain the balance between load and generation and to resolve transmission congestion through a centralized auction process. At times when there is no transmission congestion, prices in all zones are equal. When transmission congestion limits the transfer of power between zones, prices will typically be higher in zones that are import constrained. Prices are typically lower in the West zone because the West zone is export constrained and prices within that zone are affected by the large amount of low-cost wind energy.

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 market clearing price of energy (MCPE) in the balancing energy market generally followed natural gas prices over the last two years, averaging $34 per MWh in 2009 and $42.14 per MWh in 2010, compared to $77.19 per MWh in 2008. Figure 2 shows that average balancing energy prices generally reflect natural gas prices for all months except

June 2009, when ERCOT experienced congestion it was not able to resolve efficiently, and August 2010 when temperatures were unusually high throughout the month.

Figure 3 - Monthly Average ERCOT Balancing Energy Prices in 2009-2010 v. Gas Prices



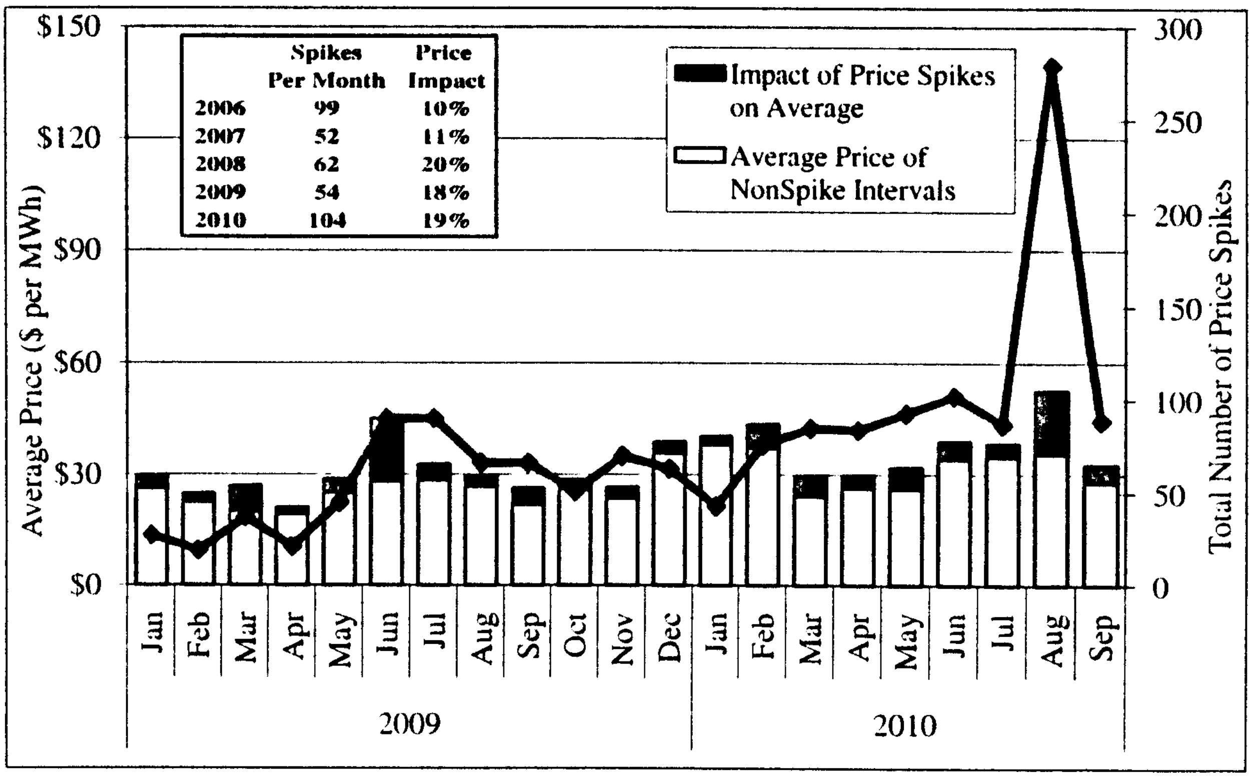
A large number of energy price spikes occurred in the balancing energy market in June 2009 and August 2010 because of transmission congestion and unusually high temperatures. A price spike is defined as a price that exceeds 18 times the price of fuel (natural gas.) Figure 3 shows the number of price spikes by month and the impact of the spikes on prices.[76] In 2009, the average monthly number of spikes was 54, while in the first nine months of 2010 that number increased to 104 due to the high number of weather-related price spikes in August 2010. August 2010 had a record number of price spikes, including a price of $2200 per MWh in one interval on August 23, when ERCOT experienced a new peak load of 65,770 MW. The Commission's mandated cap on offer prices is currently at $2250 per MWh (ensuring that prices will not exceed this limit most of the time)[77] and will increase to $3000 per MWh two months after the Nodal start date of December 1, 2010.

[76] Source: 2009 State of the Market Report, for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd, p. 7.

[77] Under certain circumstances when ERCOT experiences transmission congestion that is difficult to resolve, the price can theoretically go higher than the offer cap.

The impact of price spikes is shown by the top portion of the stacked bars in the graph. Price spikes account for a small portion of total intervals, but they have a significant impact on overall price levels. Price spikes raised the average price of energy by 18% in 2009 and 19% in 2010. Price spikes play an important role in signaling to the market the need for additional generation capacity. While the implementation of the nodal market should reduce the number of price spikes related to transmission congestion, as it provides a more effective means of managing congestion, price spikes that result from weather-related demand are an indication that more resources are needed for the hottest hours of the summer.

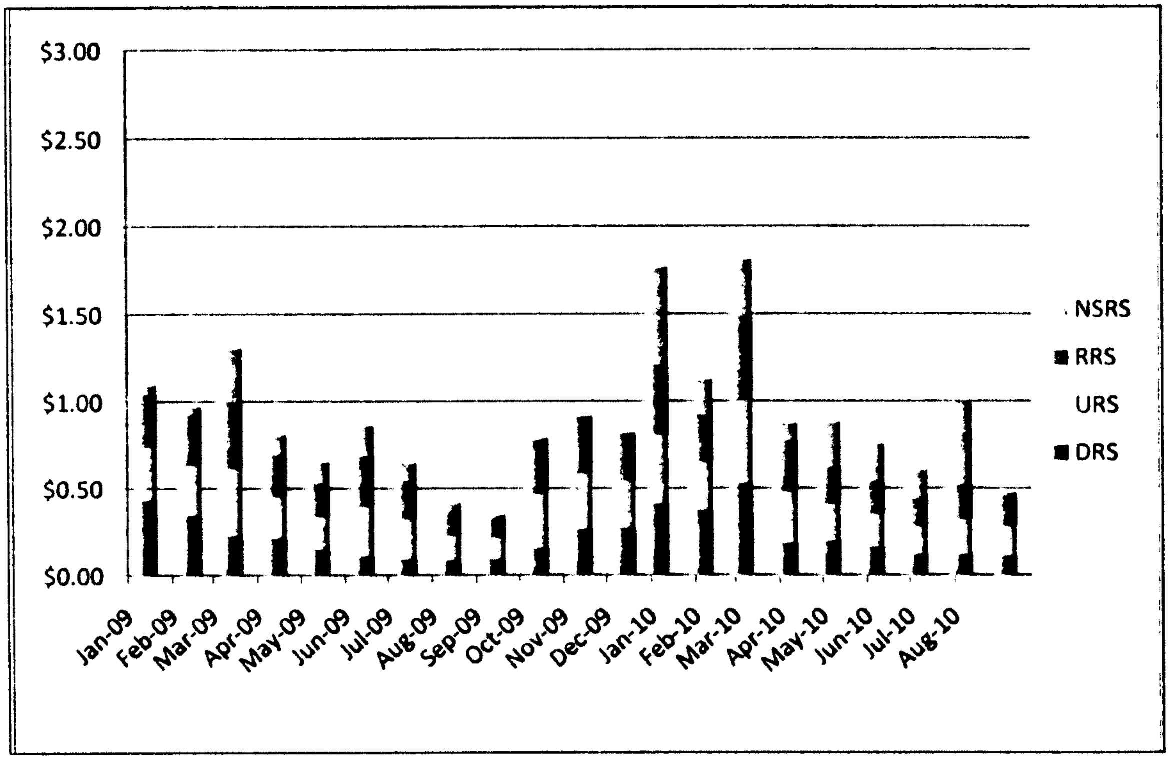
Figure 4 - Average Monthly Balancing Energy Prices and Monthly Number of Prices Spikes in 2009-2010



c. Ancillary Service Capacity Market Prices

As the system operator, ERCOT procures ancillary services, including short-term capacity reserves and balancing energy, which it deploys as needed to meet system demand, maintain reliability, and resolve transmission congestion. The capacity reserve services include regulation up (URS), regulation down (DRS), responsive reserve (RRS), and non-spinning reserve (NSRS). They are procured the day ahead of the operating day and their prices vary in relation to balancing energy prices. In 2009 and 2010, the cost of procuring capacity reserve services added less than $2.00 to the price of each MWh. Figure 4 shows the monthly average amount ancillary services added to the price of a MWh of Load.

Figure 5 - Monthly Average Ancillary Service Prices per MWh of Load, 2009-2010



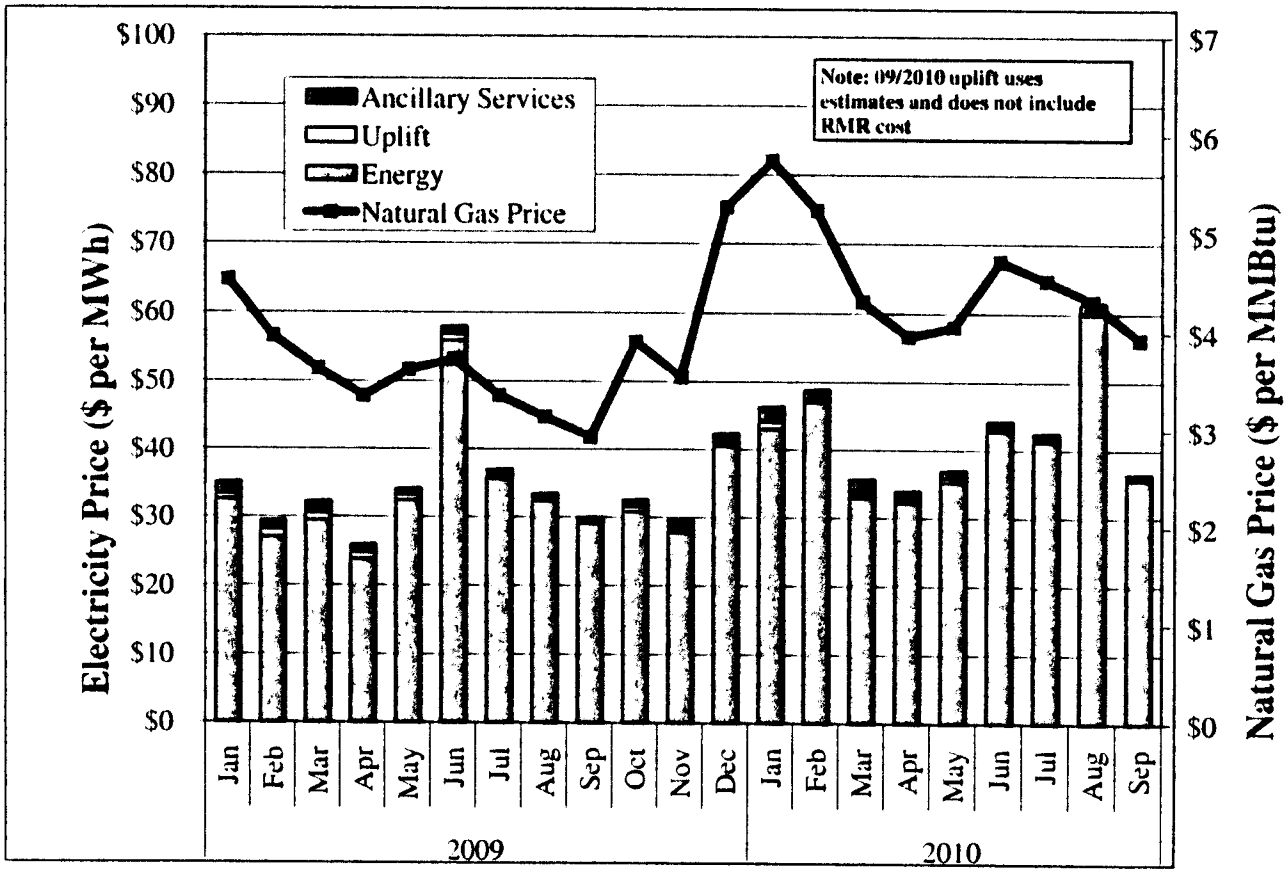
d. All-in Price for Electricity

A total or "all-in" cost of electricity at the wholesale level can be calculated by summing the costs for balancing energy, capacity reserve services, and other charges paid for by loads. Energy costs make up the bulk of the all-in cost, with capacity reserve services and uplift charges accounting for about five to eight percent of the total. Uplift charges represent additional services that ERCOT purchases to maintain system reliability but which ERCOT cannot assign to a specific market participant and are spread to the market on a load ratio share basis.

Average all-in prices for electricity in ERCOT were $35.09 in 2009 and $43.02 in 2010, compared to $78 in 2008. In comparison, in 2009 all-in prices for electricity were $38 in the California electricity market, $55 in the New York market, $50 in the PJM market, and $59 in the New England market.[78]

[78] *2009 State of the Market Report for the ERCOT Wholesale Electricity Markets*, Potomac Economics, p. 4.

Figure 6 - Average All-in Price for Electricity in ERCOT vs. Gas Prices, 2009-2010



The figure indicates that natural gas prices were the primary driver of all-in electricity prices in ERCOT in 2009-2010.

c. Congestion

ERCOT's function is to manage the flow of power over the transmission system. When the power flow over transmission facilities reaches the operating limits of the facilities, ERCOT must restrict the power flow over such facilities, and it does so in two ways. In the case of inter-zonal congestion, the congestion affects the interface between two zones. To relieve inter-zonal congestion, ERCOT will reduce energy production in the exporting zone and increase it in the other zone to manage flows between the two zones. The cost of managing inter-zonal congestion is directly assigned to the generators that cause the congestion by attempting to transfer power over the congested interface. In the case of intra-zonal or local congestion, ERCOT manages the congestion by re-dispatching generating resources on each side of the local constraint, and the cost is uplifted to all loads.

The cost of resolving inter-zonal congestion was $349 million in 2009, and $34 million in the first nine months of 2010. The costs for resolving local congestion was $115 million in 2009 and $55.56 million for the first nine months of 2010.

Figure 7 - Zonal and Local Congestion Charges, Jan. 2008 to Jul. 2010

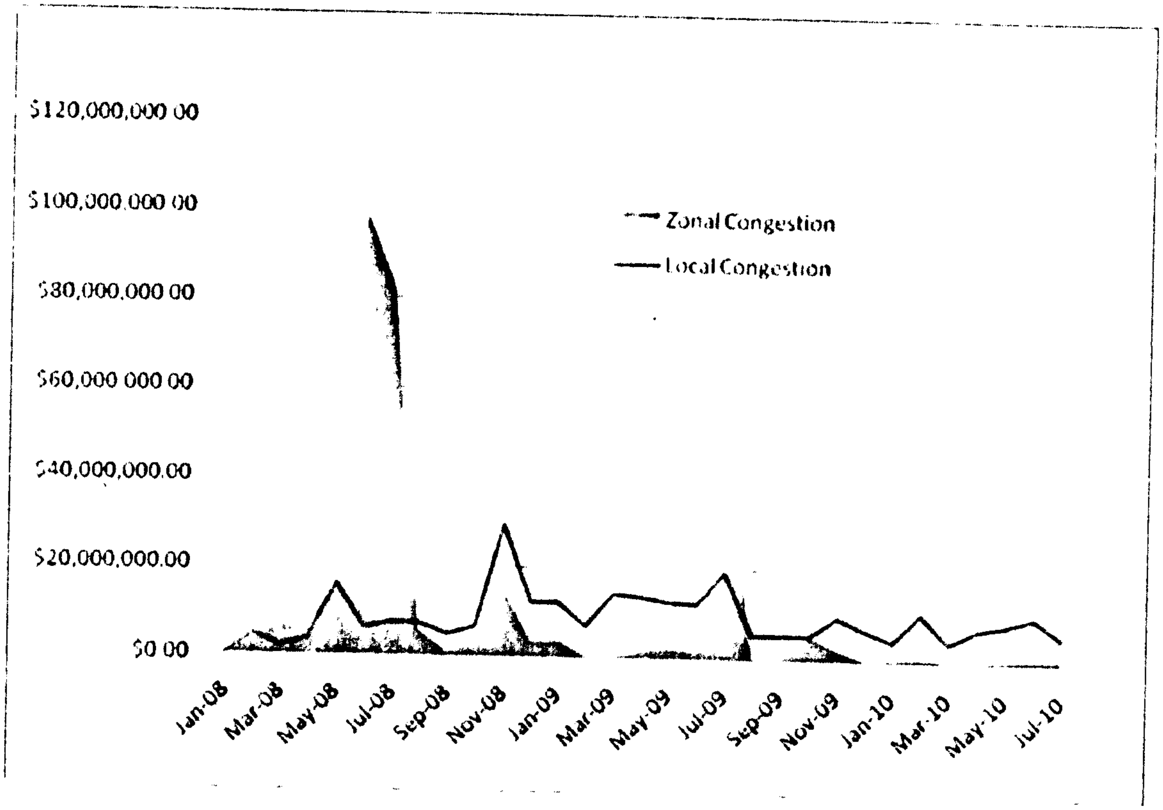


Figure 5 shows that in June 2009 very high congestion existed in ERCOT, some of which occurred on the North to South interface. This was due to very high temperatures and associated increases in electricity consumption at a time when a number of generating facilities in the South zone had experienced an outage. This combination of events led to an increase in the frequency of congestion on the North to South interface as well as local congestion related to import limitations into the San Antonio area from the north. ERCOT implemented a temporary transmission switching solution in late June that effectively increased the transfer capability on the North to South interface.

In 2009-2010, inter-zonal congestion was most frequent on the West to North interface, followed by the North to Houston and the North to South interfaces. Both the frequency and the cost of resolving congestion over the North to Houston and the North to South interfaces were significantly reduced in 2009 compared to 2008. The decreased congestion on these two interfaces is primarily attributable to a revision of the ERCOT Protocols that allowed ERCOT to use more efficient tools to manage inter-zonal congestion.

The West to North interface was congested more frequently than any other interface in 2009. The primary reason for the high frequency of congestion on the West to North interface is the significant increase in installed wind generation relative to the load in the West Zone, and the limited transfer capability to the broader market.

2. Retail Market Development and Prices

a. Available Choices for Customers

An important gauge of retail market competitiveness is the number of providers competing for customers. Today, a wide variety of products and service offers are available for Texans. By June 2010, 86 REPs were providing electric service to customers. There are 52 REPs serving at least 500 residential customers, and residential customers throughout the competitive market have dozens of providers from which to choose. As of September 3, 2010, customers visiting the Commission's PowerToChoose website would find as many as 38 REPs offering products throughout the competitive area of the state. Those REPs were offering as many as 233 different products in various territories, including 26 REPs which in combination were offering 68 different environmentally beneficial products with 100% renewable content at fixed and variable rates as low as $0.09 per kWh and $0.08 per kWh, respectively.

The number of REPs and competitive offers has continued to grow steadily since 2002. ERCOT reports that 26 new REPs entered the market in 2009, up from 19 in 2008. Residential customers have about 2.5 times more options than they did at the end of 2008.

Table 8 - Number of REPS Serving Residential Customers by Service Territory

Transmission and Distribution Utility	Number of REPs Serving Residential Customers (Incl. affiliated REPs)	Number of Residential Products	Number of Products with 100 % Renewable Content
Oncor	38	233	53
CenterPoint	36	233	55
AEP TCC	37	225	68
AEP TNC	37	226	67
TNMP	35	222	61

Texas continues to be recognized as the most successful competitive retail market in North America as demonstrated by its number one rank for the past three years in the Annual Baseline Assessment of Choice in Canada and the United States. This assessment noted the state's progress in implementing retail electric choice for residential customers, and Texas was the only market ranked "excellent" in the commercial and industrial category for the past two years.[79]

Reduced electricity prices have increased overall customer satisfaction with REPs. The J.D. Power and Associates' 2010 Texas Residential Retail Electric Provider Customer Satisfaction Study, now in its third year, reveals that residential customer satisfaction

[79] http://www.defgllc.com/content/defg/errc.asp

with price, the major factor in overall satisfaction, improved in 2010 to 610 on a 1,000-point scale, up 9 points from 2009. The study shows that in 2010, 41% of customers have been with their current provider for at least three years, versus 49% in 2009, with slightly more than 10% "highly committed" to their REP and another 25% indicating they "definitely will" stay with their REP. Nearly 10% of customers indicated that they were using renewable energy, an increase from seven percent in 2009, with satisfaction among such customers 120 points higher than customers on other pricing plans.[80]

b. Residential Rates

Retail competition started January 1, 2002, when all residential customers in the competitive areas of ERCOT were moved from fully regulated service to 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 incumbent 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 expired on January 1, 2007, at which time all customers began to be served at rates set by market forces.

Electricity rates in Texas are greatly affected by natural gas prices as gas is burned to generate about 42% of electricity (2009), with its share increasing even more during periods when demand is high. In the last two years residential rates have seen a steady decline from the highest levels of mid-2008 when natural gas prices peaked at above $13 per MMBtu. With natural gas prices averaging $4.54 per MMBtu in the first nine months of 2010, the most competitive offers in the Texas power market are below the level of prices before the introduction of retail competition.

The figure below shows the average standard residential rate offered by incumbent providers against the lowest competitive offers across all service territories. As of mid-2010, legacy providers' standard rates were 12 to 57% higher than January 2002 prices, while the average, lowest competitive offers were slightly above $0.08 per kWh, which almost mirrored the rates in early 2002. Savings of up to 35% relative to the legacy providers' standard rate were available for a typical residential customer using 1,000 kWh per month. Competitive rates were even lower later in 2010. Numbers used in the following figures and charts are based on Commission data used in compiling the average annual rate comparison and the monthly retail electric service bill comparison as well as REP offers posted on the Power To Choose website.

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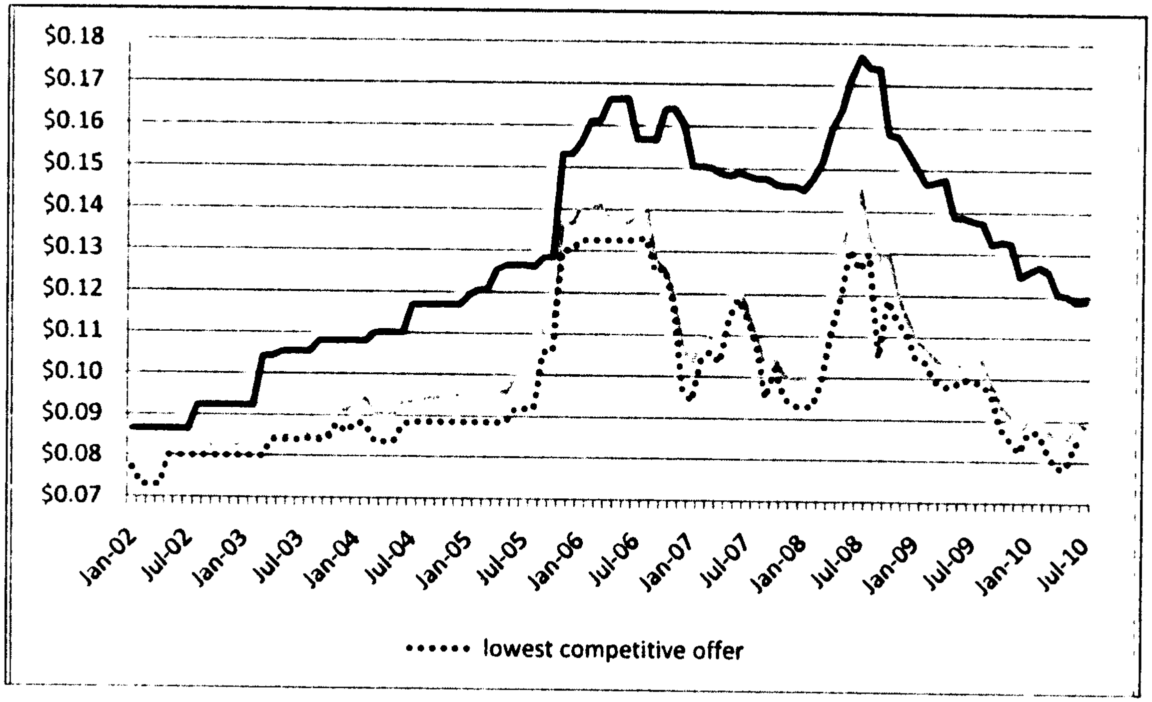
[80] J.D. Power and Associates Press Release: August 18, 2010, http://businesscenter.jdpower.com/news/pressrelease.aspx?ID=2010157.

Figure 8 - Average Incumbent Service Offers vs. Average Lowest Competitive Offer



The figure below shows that the most competitive offers in the Texas power market have decreased an average of 13.1% for fixed rates and 17.5% for variable rates, not adjusted for inflation, since the state opened its market to retail competition in 2002.

Figure 9 - Lowest Retail Fixed Rates in Texas vs. Last Regulated Rates

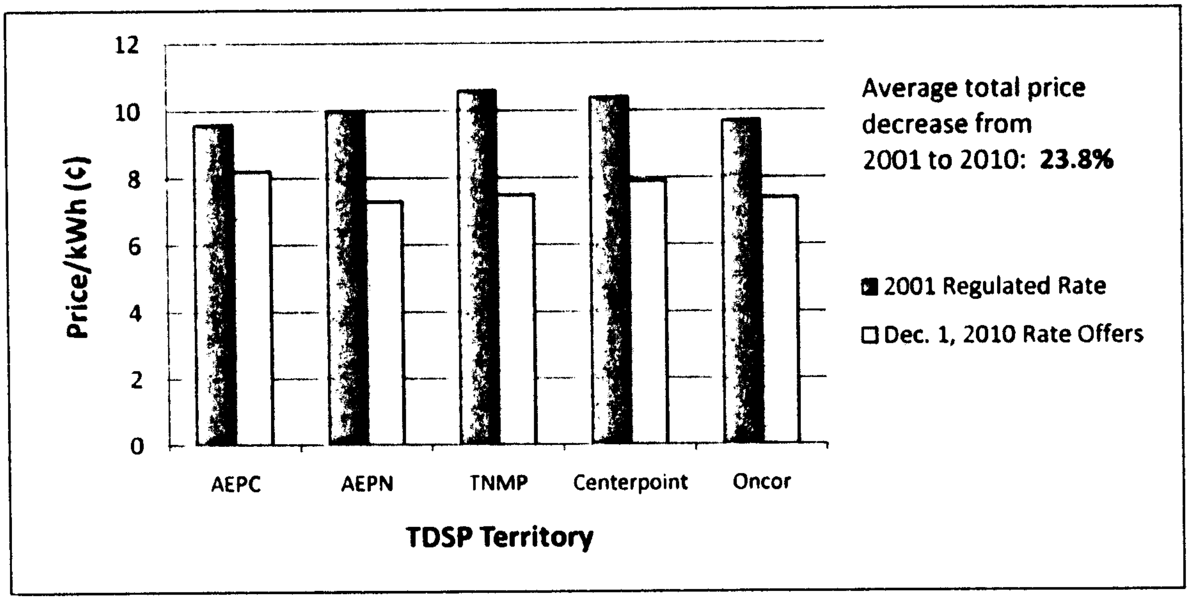
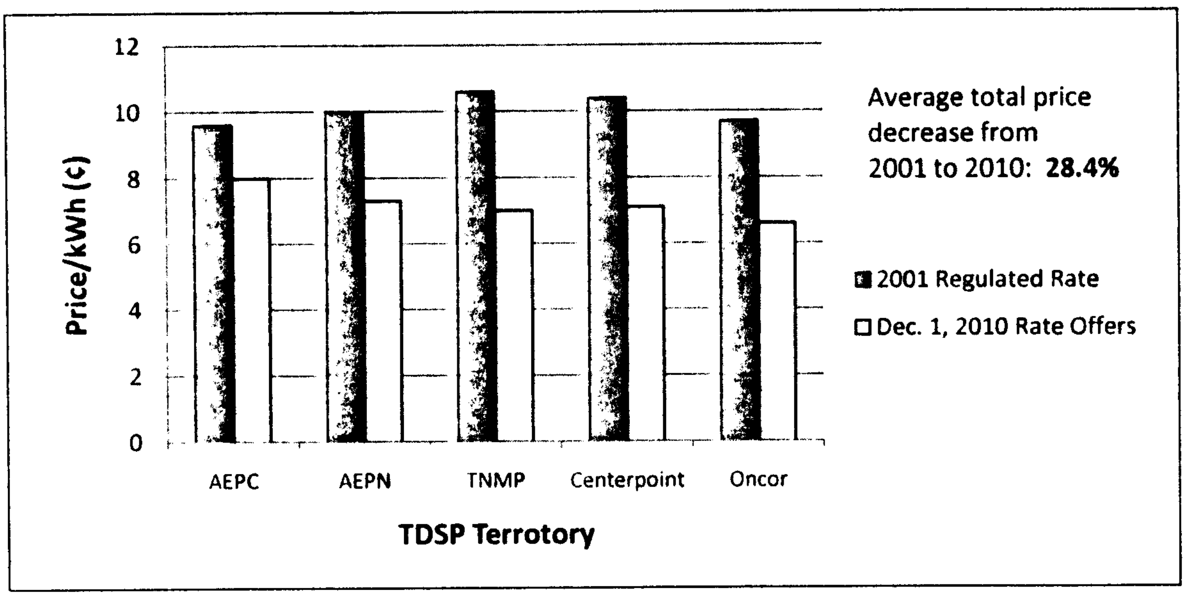
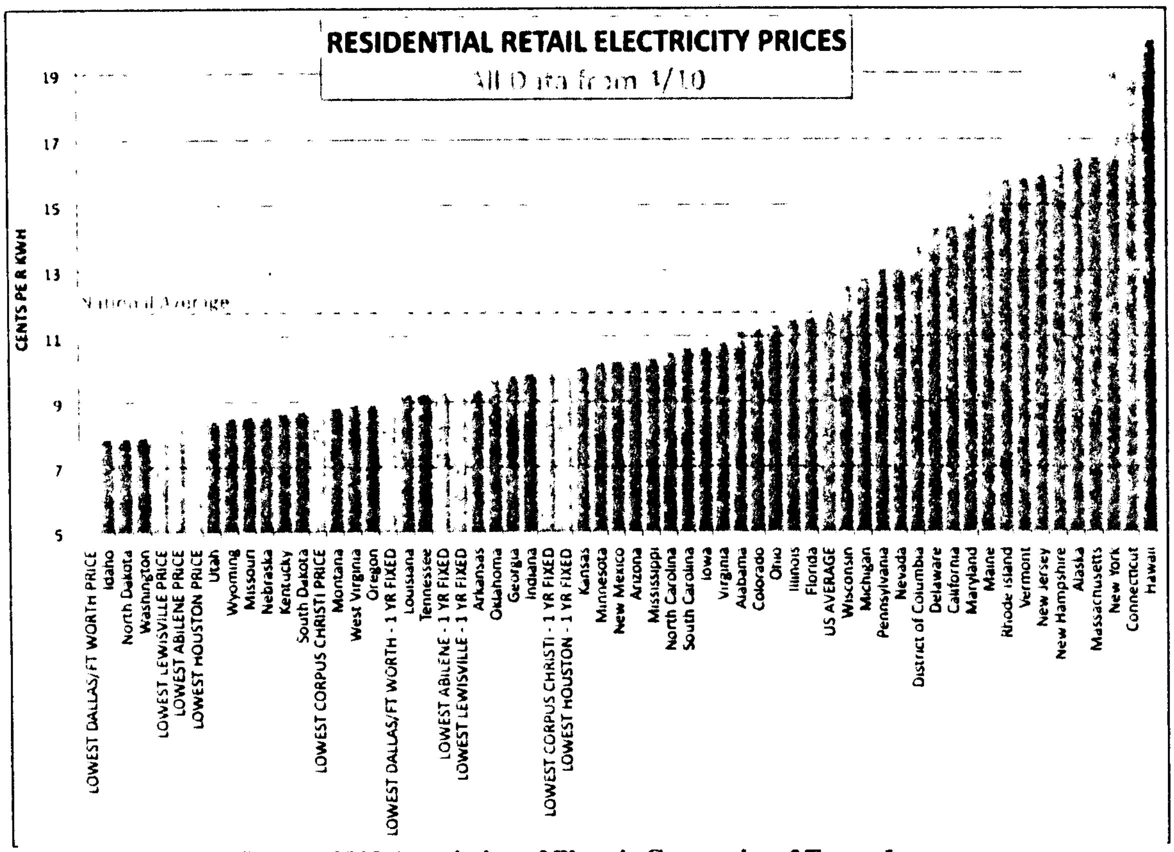


Figure 10 - Lowest Retail Variable Rates in Texas vs. Last Regulated Rates



As demonstrated in the following chart, every competitive area in Texas has variable and one-year fixed rates that are up to three cents per kWh below the national average.

Figure 11 - Lowest Retail Rates in Texas Compared to Other States



Source: 2010 Association of Electric Companies of Texas, Inc

B. Switching Activity

As of June 2010, over 3.4 million individual customers were taking service from REPs other than one of the incumbent providers, based on data reported to the Commission by the TDUs. This accounts for more than 52% of all customers in service areas open to competition. Of these customers, 83.7%, or approximately 2.9 million, are residential customers. Another 504,000, or 14.5%, are customers taking delivery at secondary-voltage levels, such as retail establishments and offices. The balance consists of approximately 6,000 large facilities taking high-voltage power, such as factories and refineries, and 56,000 lighting systems, such as streetlights and security lighting.

In June 2010, a total of 13.6 million MWh of electricity was consumed by customers of a REP other than a legacy provider, accounting for approximately 68% of all electricity 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. Even though residential customers account for 83.7% of total switches, they represent only 29% of the electricity sold to switched customers in June 2010.

The figures below show that switching rates vary by service area, with the highest rate of switching in the TNMP service area, at 66.89%, and the lowest rate in the Oncor service area, at 45.86%. Oncor's is the only service area yet to achieve a 50% switching rate. The lowest level of energy consumed by customers of competitive REPs is also in the Oncor service area, at 62.53%, and the highest is in the AEP North service area, at 87.05 %.

Figure 12 - Customers by REP Status

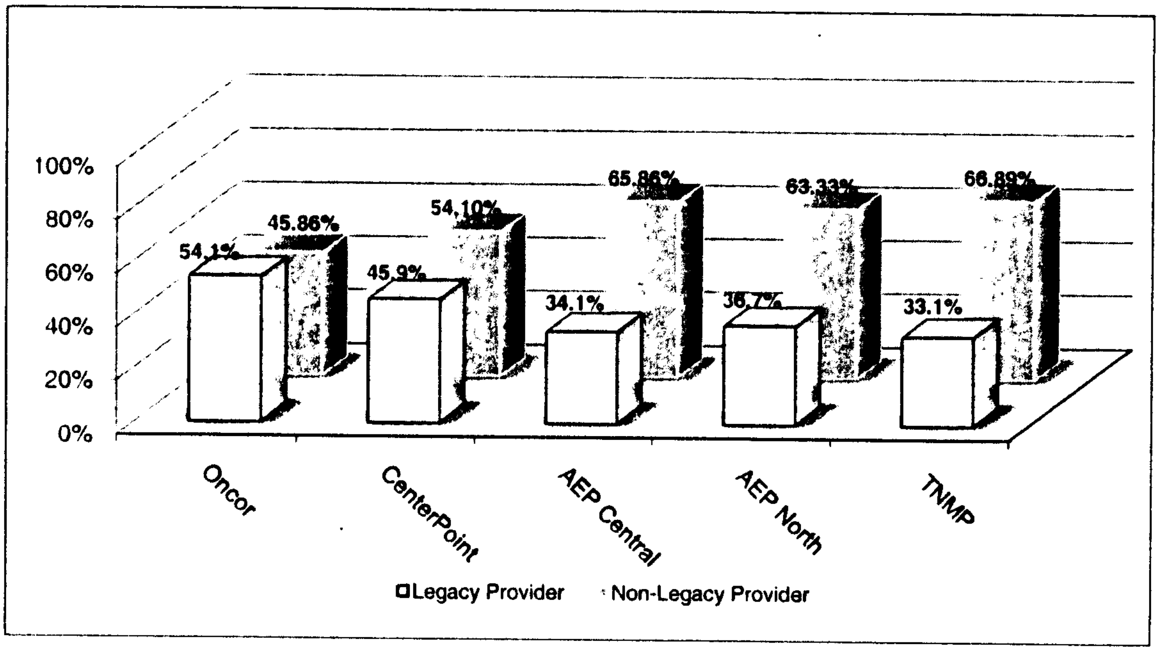
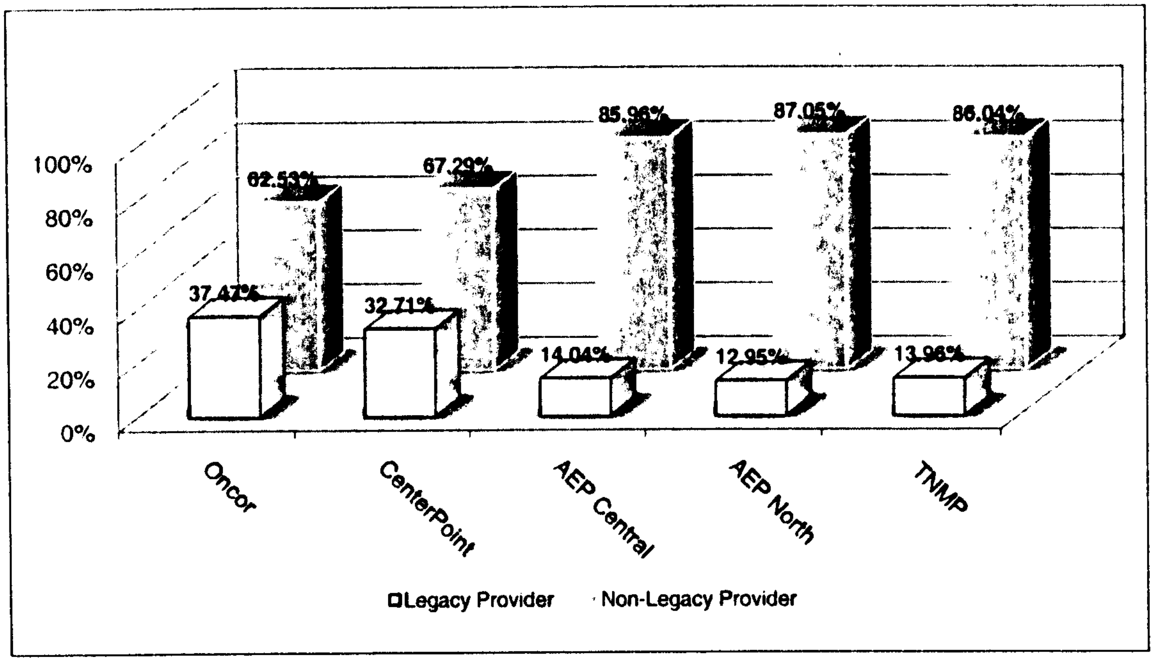


Figure 13 - Energy by REP Status



1. Residential Customers

There has been a consistent trend of residential switching, with about seven percent of residences annually starting to take service from alternative providers from 2002 to 2008, slowing down to about four percent in the last two years. Even though retail choice exists in more than a dozen states, switching rates for residential customers in those states are far lower than in Texas. Only Connecticut, New York and Massachusetts have achieved a measurable success in residential customer switching, with the rates of 29%, 17.9% and 14%, respectively. In all other states offering retail choice, the residential switching rates have been negligible or even decreased in the last few years. Texas is the only state where more than half of residential customers have chosen to be served by non-legacy providers. This is further evidence that the state's well-structured competitive market is promoting competition among market participants to the economic benefit of customers.

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 competitive REPs marketing throughout the competitive areas of the state. REPs have been most successful in attracting new customers in the TNMP area, with a switching rate of 68.2% in June 2010 versus 49.4% in June 2008. 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 represent new customers who have selected a incumbent provider as not having switched.

Figure 14 - Residential Customers with Non-legacy REP by Service Territory

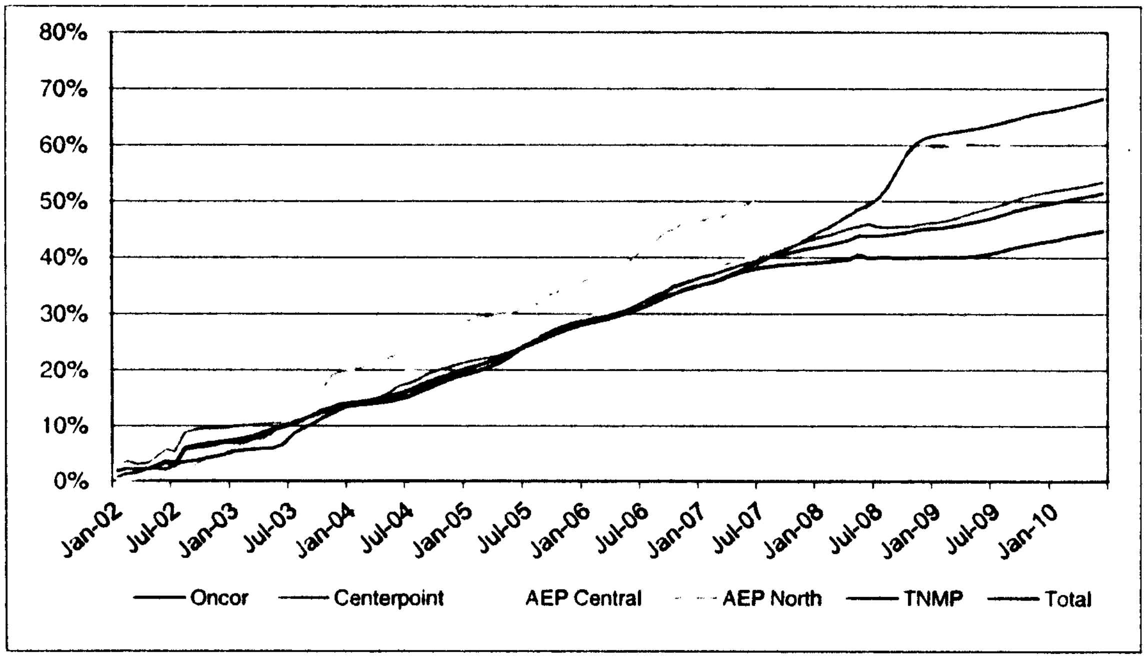


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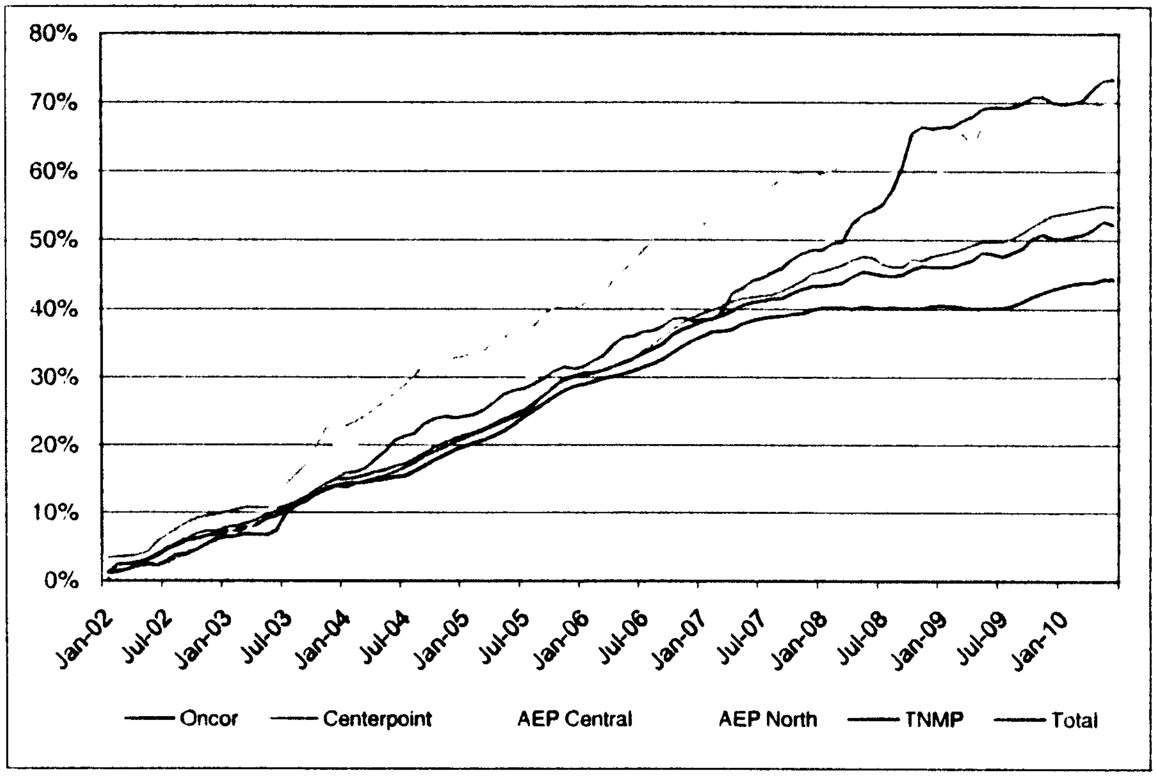
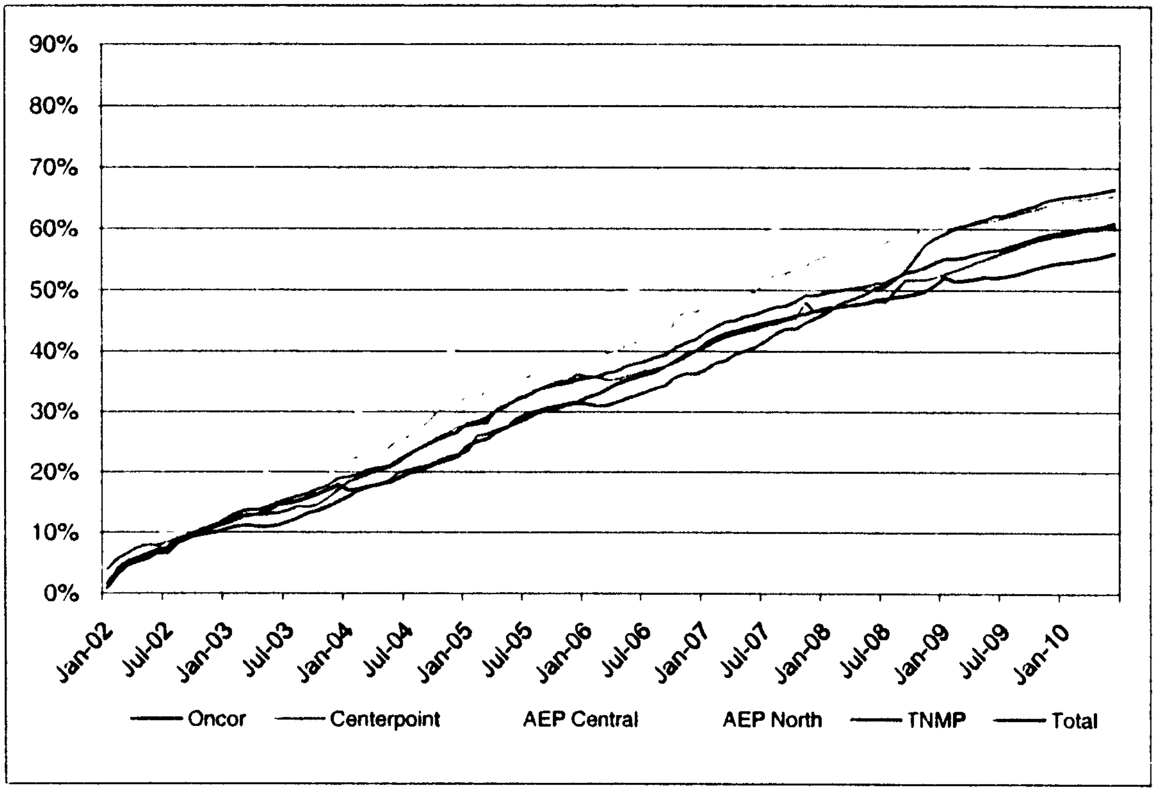
Figure 15 - Residential MWh Switched to Non-legacy REP by Service Territory



2. Secondary Voltage Commercial and Industrial Customers

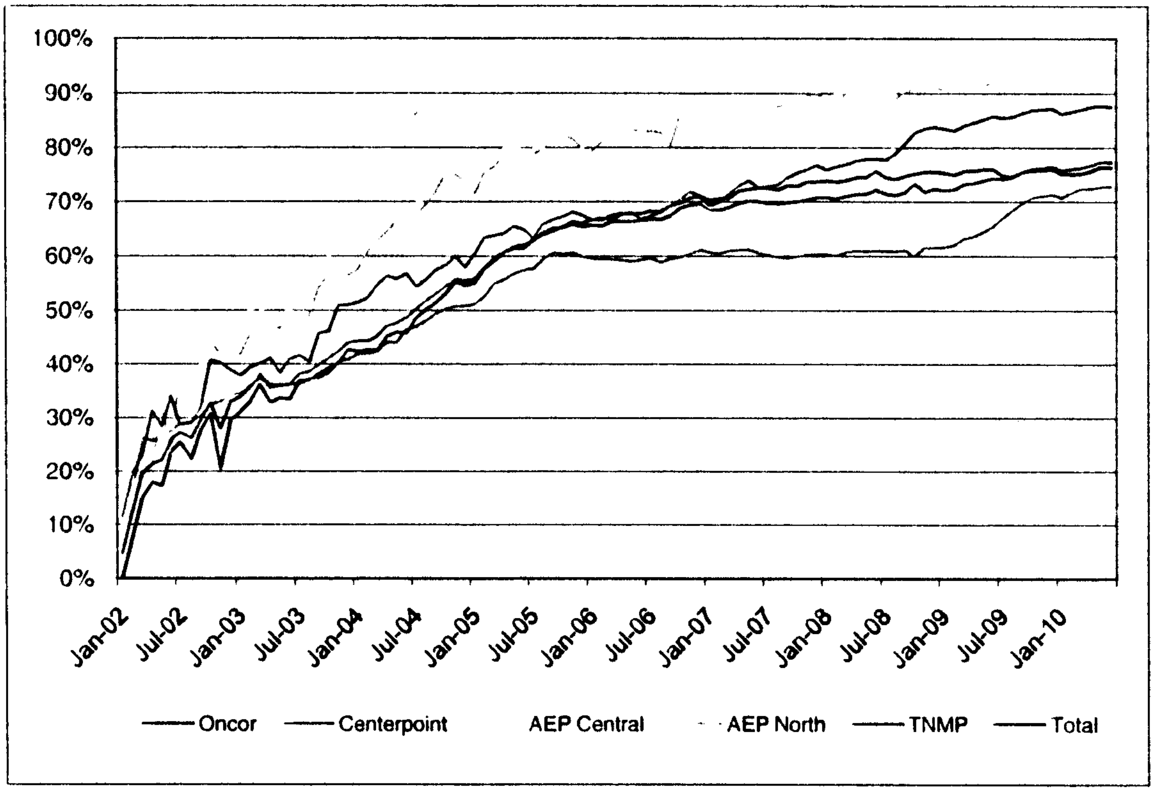
Commercial and industrial customers taking service at the secondary-voltage level have shown a greater tendency to switch than residential customers. These customers typically have higher energy usage and higher electric bills than most residential customers, and thus they have greater incentive to seek lower rates. As of June 2010, 61% of commercial and industrial customers had changed providers, ranging from 56.1% in the Oncor territory to 76.9% in the AEP Central service territory. These switching counts have grown more or less linearly since 2002.

Figure 16 - 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 77.3% of MWh sold to this class in June 2008 were sold by REPs other than the legacy provider. By territory, as little as 72.9% of MWh in the Oncor territory to as much as 94.8 of MWh in the AEP Central territory are sold by non-legacy providers.

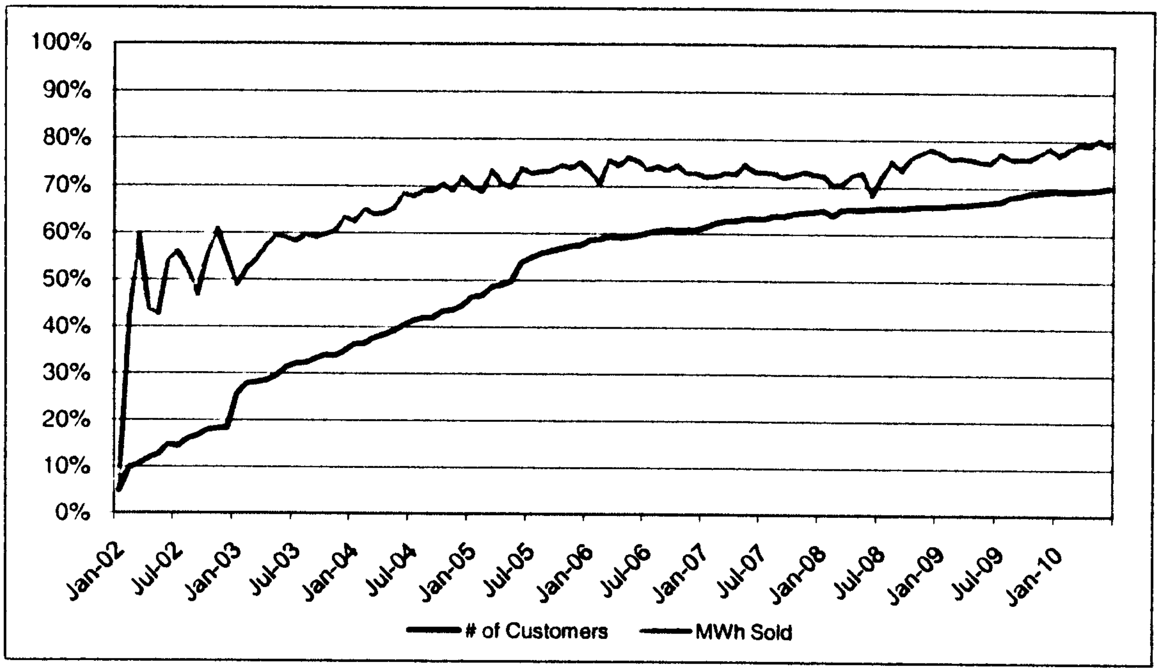
Figure 17 - Non-Affiliated REP Share of Secondary Voltage MWh



3 Primary Voltage Commercial and Industrial Customers

Primary-voltage and transmission-voltage customers are large electricity consumers. Approximately 70% of the primary and transmission customers had switched by June 2010, registering an increase from about 65% in June 2008. The remaining 30% stay with the legacy provider with rates set by negotiation between those large customers and the REPs. Approximately 79% of MWh sold to this class were provided by REPs other than the legacy provider, up from 68% two years ago.

Figure 18 - Primary Voltage Customers not with Non-legacy REP



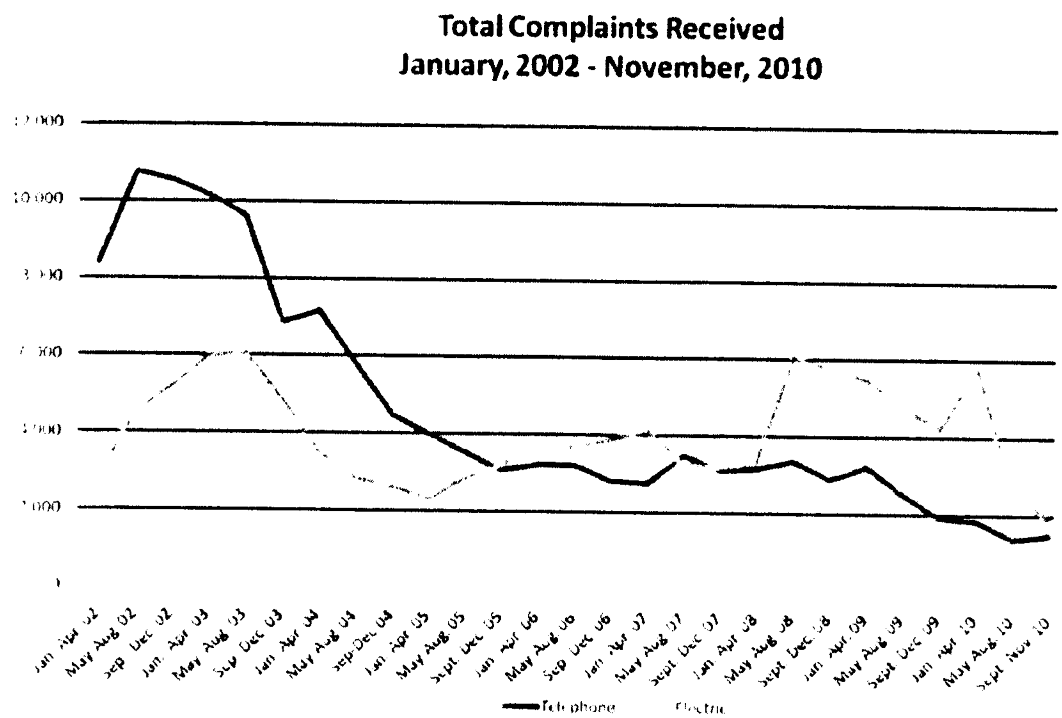
IV. Assessment of Other Senate Bill 7 Goals and Benefits

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 that 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 CPD experienced a spike in the number of customer complaints resulting from high electricity prices coupled with some REPs exiting the market. Also prompting the spike were complaints from customers who were on variable rate plans because in this time frame variable plans generally quoted the highest electricity prices offered by REPs.

The increase can also be explained by increased customer awareness of not only the structure of the deregulated market and various REP plans and offers, but also of events affecting the market.

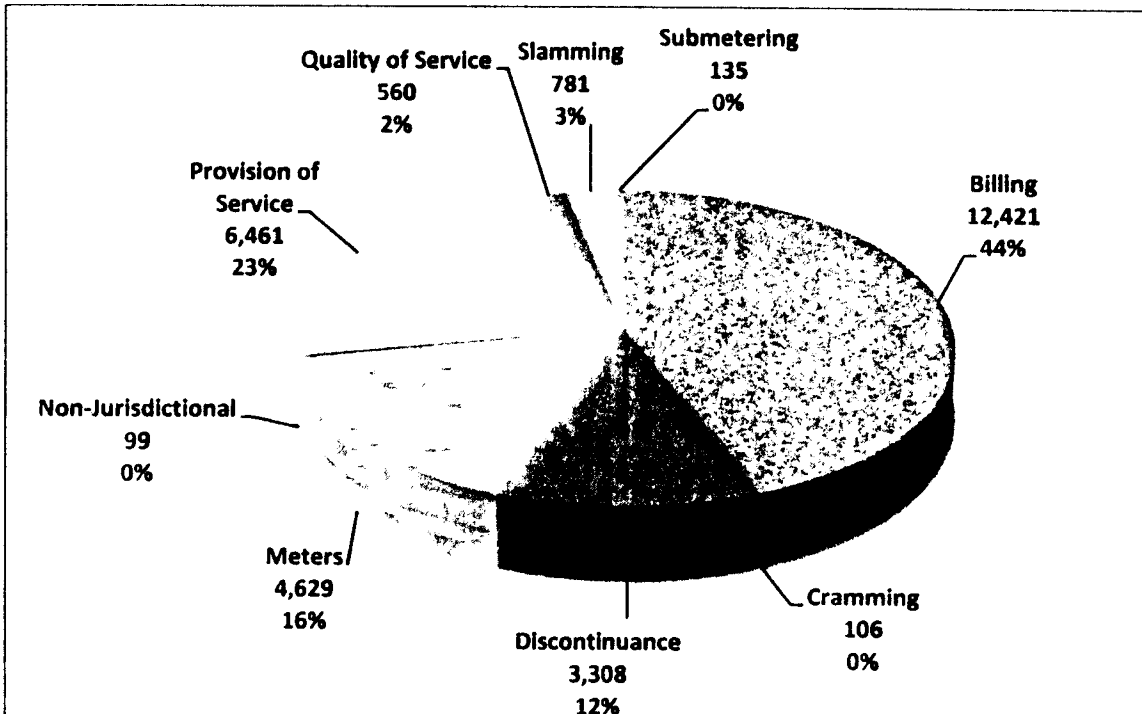
Figure 19 - Total Complaints Received



Complaints remained high in September 2008 due to the onset of Hurricane Ike and to complications involving customers who were affected by REPs that discontinued their business operations in the deregulated market. Additionally, many REPs initiated operational upgrades to their bill format and billing systems to comply with new or amended customer protection rules and provisions. In some cases, the upgrades were not seamless and prompted complaints covering billing errors, delayed billing and errors in billing the correct premise.

Thereafter, a steady decline in complaints occurred until December 2009. In January 2010 complaints gradually increased and spiked in April. Customers to whom advanced meters were deployed expressed concerns that their advanced meters were faulty or inaccurate because their meter reads measured an increase in usage after installation. It was ultimately concluded that in November, December, January and February record-breaking cold weather was experienced throughout most of the state causing higher than normal energy usage. Since April, a noticeable decline in complaints can be attributed to low and stable electric prices combined with mild temperatures and rainfall in the spring and early summer months. By the end of August 2010, complaints continued to remain low and trended downward. Complaints involving advanced meters also subsided due, in part, to the results of an independent study requested by the Commission that found advanced meters to be exceptionally accurate. This study is discussed more fully later in this report.

Figure 20 - Electric Complaints Received



A total of 28,500 electric complaints were received from September 2008 through August 9, 2010. The deployment of advanced meters and Hurricane Ike accounted for the 21% increase in billing complaints and an 81% increase in meter complaints when compared with the previous period of Sept 2006 through August 2008. Such complaints included high bills/usage, AMS surcharges, misapplied taxes, estimated meter reads, meter tampering and errors in matching the premise designation with the correct meter.

With the installation of advanced meters, high billing was a prominent complaint issue. During the spring of 2010 the Commission retained Navigant Consulting, LLC, an independent third party, to evaluate the accuracy of the meters being deployed. Many of the issues investigated were in response to complaints filed with the Commission, as well as various media reports and inquiries, targeted at concerns over the accuracy of the meters currently being deployed in the three utility territories.

Navigant reported that, in its opinion, the vast majority of smart meters currently installed by Oncor, CenterPoint and AEP Texas are accurately measuring and recording electricity usage and communicating that information through the AMS for use in customer billing. Navigant noted, however, that the evaluation and investigation uncovered certain discrete groups of smart meters that were not performing at acceptable levels, and where a certain number of customers appeared to have been impacted. Further, Navigant stated that it was apparent that any potential impact to customers from the observed smart meter failures could have been limited, if not avoided entirely, if the respective TDU had effectively monitored and analyzed the performance of these smart meters using the information available to it.

The investigative process revealed other underlying issues contributing to the increase in complaints. These issues include:

> discovering meter tampering with the old meters during removal and installation of advanced meters resulting in back billing;
>
> small commercial customers either initially experiencing demand ratchets or experiencing an increase in demand;
>
> customers withholding bill payments until the advanced meters underwent testing for accuracy. After their accuracy was established many of these customers entered into deferred payment plans;
>
> customers discovering they selected variable rate or indexed rate plans;
>
> customers failing to renew their pricing plan or switching to a new provider and subsequently placed on a variable rate plan per their Terms of Service agreement;
>
> customers incurring early termination fees because they were unaware of the expiration date of their contract; and
>
> customers assuming a critical care status without approved designation and withholding bill payments. Customers subsequently resorted to entering into deferred payment arrangements and working with local assistance agencies.

Complaints regarding provision of service increased by 26%, in most cases customers remitted payments and receiving delayed electric service or no electric service at all. Slamming complaints decreased by 23%, as did Discontinuance of Service complaints by 13% and Quality of Service complaints by 9%. The decreases can be attributed to ongoing process improvements by market participants and increased customer education and awareness of their rights and protections.

Increase Benefits and Functionality of Advanced Meters for Customers

In an effort to realize the benefits and functionality of smart meters for customers, a rulemaking project, Project No. 38674, *Amendments to Customer Protection Rules relating to Advanced Meters* was opened. In this project, the Commission will explore the expansion of business hours and adding Saturday as a business day for the purpose of processing advanced meter related service orders. The Commission will also explore the option of giving customers the ability to switch REPs within one business day. Other issues that would require amendments to customer protection rules may also be examined in order to fully provide benefits to customers from investment in smart meters.

B. Renewable Energy Mandate

Texas established a renewable energy portfolio standard through 1999 amendments to PURA. The amended statute established renewable energy goals and an implementation mechanism, renewable energy credits. These credits are earned by companies that produce renewable energy, and they are required to be retired by REPs and electric utilities. The retail providers and utilities buy the credits from producers, and the sales and purchases of the credits establish a market value for the credits.

The original legislation established a goal of 2,000 MW of new renewable resource capacity by 2009. In 2005, PURA was amended to increase the goal to 5,000 MW of new renewable capacity by 2015. The amendments also established a target of 500 megawatts of non-wind renewable capacity by 2015 and 10,000 megawatts of renewable capacity of any type by 2025. Currently 10,000 MW of new renewable capacity is in operation in Texas, so the 2015 goal and 2025 target have been met.

The 2005 legislation also directed the PUC to designate CREZs and adopt a transmission plan to move renewable energy from these zones (areas of productive wind generation in West Texas) to other areas of Texas.[81] The PUC has designated CREZs in West Texas,[82] has adopted a transmission plan that will permit a significant increase in the production of wind energy in West Texas and delivery of the wind energy to more populous areas of the State outside of West Texas,[83] and has designated the transmission

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[81] PURA § 39.904(g) Tex Util. Code §

[82] Commission Staff Petition for Designation of Competitive Renewable Energy Zone, Project No.33672 Order on Rehearing (Oct. 7, 2008).

[83] Commission Staff Petition for Designation of Competitive Renewable Energy Zone, Project No.33672 Order on Rehearing (Oct. 7, 2008).

companies to build the new transmission facilities.[84] The transmission plan approved by the PUC is designed to permit about 18,400 MW of wind capacity to operate within ERCOT by late 2013 or early 2014. The PUC is also considering adopting a system of renewable energy credits for non-wind renewable resources to provide incentives for the construction of non-wind renewable facilities, which could ensure that the 500 MW target is met. There are about 150 MW of qualifying non-wind resources currently in operation.

The best wind resource areas in Texas are primarily in West Texas and along the Gulf Coast between Corpus Christi and Brownsville. In many of these areas, investment in wind facilities has resulted in a significant increase in the property tax base for counties and school districts. The wind facilities have also generated employment in delivery, construction, operation, and maintenance of wind turbines and supporting infrastructure, construction of towers and other components, and other related jobs.

C. Energy Efficiency

The August 2008 State Energy Plan identified energy efficiency as one of five key areas essential to meet the energy demands of Texas consumers.[85] The State Energy Plan included recommendation number 24 stating that if the Commission study required by HB 3639 indicated 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[86].

The Commission hired Itron, Inc. to perform this study, and its report concluded that a 50% reduction of the growth in electricity demand could be met. Although the study indicated that a goal of a 50% reduction in growth in demand by 2014 was possible, the Commission was concerned with the estimated cost of $2.20 per month to the ratepayer in the CenterPoint region; $2.80 in the Oncor region; and $4.00 in the TNMP region that would be required to achieve a 50% reduction. The Commission reviewed the current cost and economic realities and ruled that a goal of 30% reduction in growth in demand by 2014 at a cost of $.78, $1.30, and $1.15 respectively would be the more cost effective energy efficiency reduction option.

Therefore, the Commission amended its existing rules relating to energy efficiency and adopted a new rule in 2010 to raise the electric utilities' energy efficiency goals from 20% of annual growth in the electric utilities' demand for electricity of residential and

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[84] *Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy From Competitive Renewable Energy Zones*, Docket No. 35665, Order on Rehearing (May 15,2009).

[85] 2008 Texas State Energy Plan, Governor's Competitive Council,

http://governor.state.tx.us/priorities/economy/industry cluster efforts/governors competitiveness council/.

[86] 2008 Texas State Energy Plan, Governor's Competitive Council, page 9.

commercial customers to 25% of the growth in demand of these customers in 2012, and to 30% of the growth in demand in 2013.[87] The new rule also:

updated the cost effectiveness standard by adjusting the avoided cost of capacity and the avoided cost of energy;

modified the calculation of a performance bonus for an electric utility that exceeds its goal; and

applied the requirement to all electric utilities, not just electric utilities that are subject to PURA 39.905.

The new rule was adopted July 30, 2010 with the purpose of pacing the increase in the energy efficiency goal in a modest manner while capping the cost on a per customer basis at a reasonable level to meet the new goals, and subsequently providing the Commission the time to evaluate the continued cost effectiveness of the program. The Commission recognized that the adoption of the amended energy efficiency rule in July 2010 was just six months prior to the beginning of the 82nd Legislative Session and that the Commission would need to make necessary changes should the Commission receive additional direction from the Legislature during the 82nd Legislative Session.

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 an energy efficiency cost recovery factor paid for by customers. In 2009 the utilities spent approximately $106 million on this program. The goals of the PURA energy efficiency program are that:

electric utilities administer energy efficiency incentive programs in a market neutral, nondiscriminatory manner;

all customers have a choice of and access to energy efficiency alternatives to reduce energy consumption, peak demand or energy costs; and

cost-effective energy efficiency measures are to be acquired for residential and commercial customers.

D Smart Grid Deployment Update

The Energy Independence and Security Act of 2007 specifies that the deployment of 'smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for smart metering, communications concerning grid operations and status, and distribution automation

[87] *Rulemaking Proceeding to Amend Energy Efficiency Rules*, Project No.37623, Order Adopting Amendments to § 25.181 as Approved at the July 30, 2010 Open Meeting (Aug. 9, 2010).

should be deployed. Texas is ahead of the rest of the country with its deployment in terms of meters deployed and features that ensure that the benefits of this investment will flow among the utility, the REP, and the customer. The Commission believes that smart meter deployment is a critical component of the evolving Texas electric market. As deployment occurs, it can enable market-based demand response, help the market to mature, yield savings for utilities, reduce bills for customers, and create efficiencies in market processes for REPs and ERCOT.

Most importantly, AMI can enhance service quality to retail customers in several areas:

expediting connection and disconnection of service;

providing a prepayment option that will reduce deposit requirements;

giving customers the tools to help manage energy costs;

enabling quicker service restoration following an outage; and

helping balance the dynamics of supply and demand.

Over 2.1 million smart meters have been installed by investor-owned utilities in Texas, but smart meters are not exclusively a Texas phenomenon. It is anticipated that by year end 2010, approximately 16 million smart meters will be in place in the U.S and 50 million by 2015. By giving customers better information about their consumption and retail rates, smart meters should reduce customer demand as customers become more efficient in their use of electricity and shift consumption to lower-cost hours, thus reducing the need for investment in new peak generation capacity.

AMI is the cornerstone and the essential building block of a smart grid. Much more than just smart meters, the smart grid is an efficient, dynamic, and more resilient electrical and communications delivery system. Like the telecom and internet revolutions, technology holds the key to the smart grid and its benefits. The smart grid and the technologies embodied within it are an essential set of investments that will help bring our electric grid into the 21st century using megabytes of data to move megawatts of electricity more efficiently, reliably, and affordably. In the process, the electric system of today will move from a centralized, producer-controlled network to a less centralized, more consumer-interactive, more environmentally responsive model.

The smart grid should facilitate identifying the extent of an outage and planning the efficient restoration of service. The results will be quicker restoration of service in the case of equipment failures that result in loss of service for dozens of customers following a thunderstorm, hurricane or tropical storm. Smart meters also automate meter reading, reducing the cost of electric delivery service and will facilitate increased automation of the distribution system, so that restoring service after some outages will be achieved without dispatching a service crew. Over time, benefits will encompass the broad areas of reliability, power quality, economic vitality, efficiency, and environmental impact.

V. Emerging Issues

A. Proposal 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 begins recovering 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 costs 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.[88] No similar provision exists, however, for

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

capital additions related to distribution facilities, whether inside or outside the ERCOT region.

AEP has suggested four basic options that could be considered as a framework for streamlining the traditional rate-setting process without diminishing current regulatory oversight. These four options include:

Distribution Cost of Service (DCOS) mechanism—this approach 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. Project No. 38298, *Rulemaking Related to Recovery by Electric Utilities of Distribution Costs,* currently pending at the Commission, incorporates this basic approach.

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

Targeted Programs—this 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—these 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.

At issue in all these 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, with Project No. 38298 pending, the Commission has not expressly considered or made a determination on this issue.

B. Operational Challenges of Wind Generation in Texas

Texas has experienced a rapid and significant addition of renewable energy generation in recent years, primarily in the form of large-scale wind generation resources. At the end of June 2010, new renewable facilities in Texas reached approximately 10,073 MW, which exceeds the January 1, 2025 legislative target of 10,000 MW. Wind represents 9,915 MW of this renewable capacity installed since September 1, 1999.

Most wind generation development has occurred in West Texas, in areas with low population. In Section II.B of this report, the subsection entitled "Competitive

Renewable Energy Zone (CREZ) Cases" provides a discussion and update of the transmission cases currently under way to expand the transmission network in ERCOT. Such expansion is necessary so that wind energy from current and future wind developments can be transported from West Texas to population centers in South, Central, and North Texas. This expansion of the electric transmission network is scheduled to be completed in the 2013-2014 timeframe. Wind developers are expected to synchronize the completion of their new generation projects in the CREZ zones of West Texas and the Texas Panhandle to coincide with the completion of the transmission network, almost doubling the current wind capacity.

It has been feasible to incorporate wind energy into the electric system operations at the relatively low levels of penetration of wind capacity that have occurred up to now. Today, wind resources constitute about 15% of the total capacity in the ERCOT region. The output of the wind farms, like the level of the wind, is intermittent and difficult to predict, and these characteristics of the wind resource are expected to present challenges to the reliable operation of the electric network when the CREZ wind facilities are completed.

In the operation of an electrical network, the level of energy produced must match the level of energy demanded by customers at all times within a narrow tolerance. The matching of energy output and energy demand is achieved, for the most part, by increasing or decreasing the output of generation facilities as demand changes. "Base load" generating plants operate around the clock to serve the minimum level of energy demanded, that is, the amount of demand that is present every hour of every day. Other plants, referred to as "cycling" plants, begin to operate and increase their output as the level of demand increases daily or seasonally. Finally, "peaker" plants are brought on line to operate a limited number of hours when demand reaches very high levels.

In an integrated utility environment, the commitment, startup, and planned output levels of generating units are under the control of the utility. In a competitive environment, a neutral third party typically has responsibility for the reliability of the transmission system and operates markets for energy and short-term capacity that it uses to match energy output and energy demand. These neutral organizations are usually Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs). ERCOT is an ISO within the Texas intrastate electrical network.

Wind energy production typically becomes a significant part of total energy production during the off-peak seasons and in the winter, and wind energy is more likely to affect reliability in these periods of lower demand. For example, on June 12, 2010, wind energy production in ERCOT reached a record of 7,016 MW, which represented 15.8% of system load at that time. On March 4, 2010, a non-peak period, wind production reached 6,272 MW, which represented 19% of system load at that time. When wind production reaches a percentage of 20% to 30% of total system load, operational problems are increasingly likely to affect system reliability. ERCOT has implemented improvements in its operations to address the current levels of wind production, such as improving the forecasting of wind production, and it continues to assess and develop measures that will allow it to continue to operate reliably, as wind development continues in Texas with the completion of the CREZ transmission plan and associated wind farms.

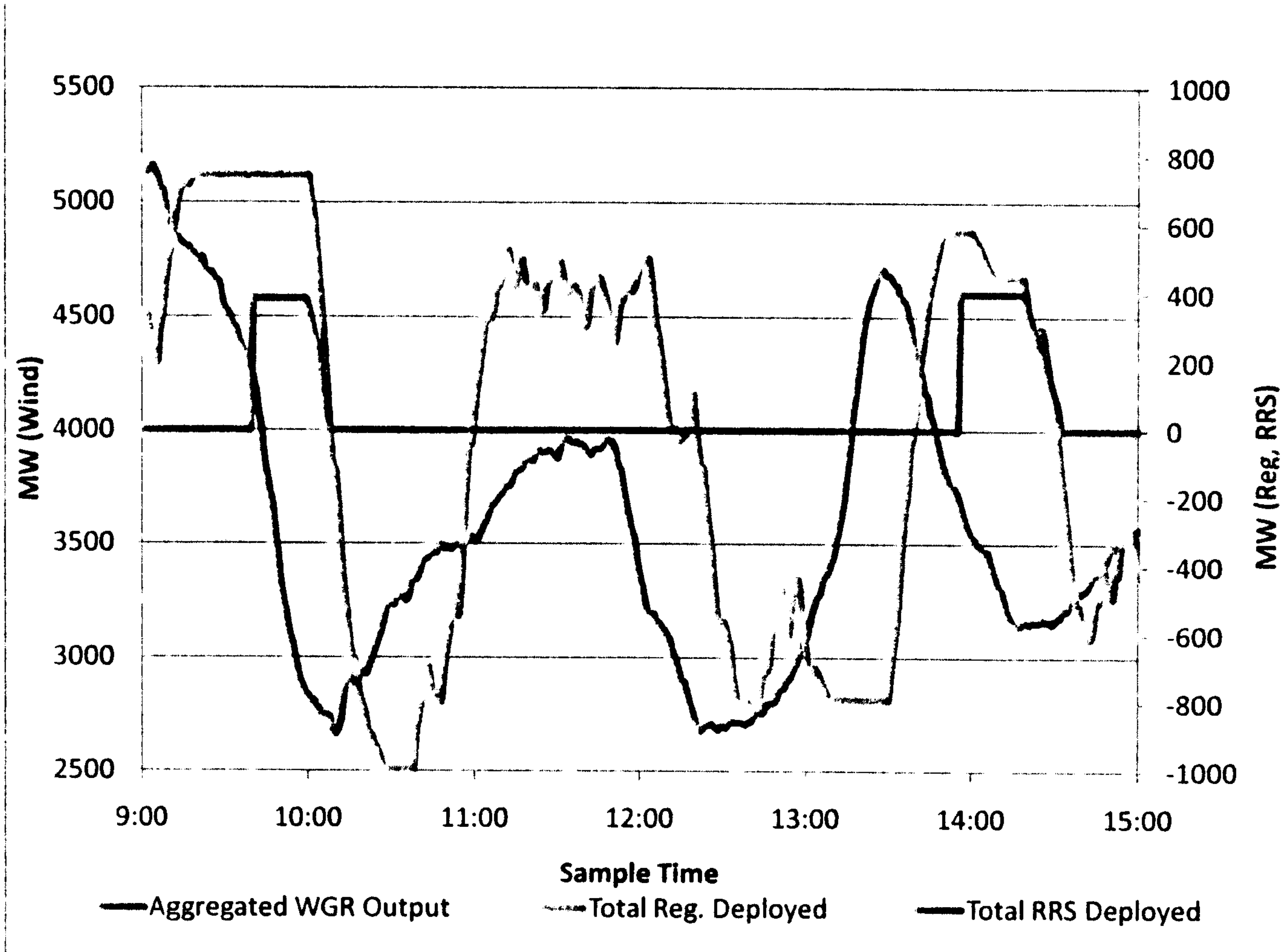
Forecast Uncertainty

It is important for ERCOT to be able to accurately forecast wind energy production so that it can dispatch resources to match generation and load at all times. ERCOT has acquired state-of-the-art forecasting tools to forecast wind generators' output. Wind generators are now required to use the wind production forecast provided by ERCOT in their daily resource plan submittals rather than rely on their own forecasts, which can have varying degrees of sophistication and accuracy.

Even with the state-of-the-art forecast of wind production there is still some disparity between the forecasted production and actual production. The risks of load forecast error, wind forecast error, and outages of the thermal generation and transmission facilities are mitigated by acquiring generation reserves that may be called into operation when needed, and it may become necessary for the system operator to quickly deploy these resources when a sudden change in wind production occurs. For example, on January 28, 2010, ERCOT experienced wind gusts throughout the day. The variability of wind generator output is shown in figure 22 below. These wind speed changes led to the deployment and depletion of operating reserves (RRS, in the figure). To address such events, ERCOT has adopted a new methodology to acquire additional operating reserves as the amount of wind generation increases.[89] In addition, ERCOT is considering adding reserve services from quick-start generating units – units that can come on line within 10 minutes. ERCOT currently has 1,000 MW of resources capable of reaching full capacity in 10 minutes, and 550 MW of announced resources with similar capability.

[89] For a discussion of the new Ancillary Services methodology adopted by ERCOT, see section C.2, Competitive Market Oversight Activities, Wholesale Market Oversight, of this report.

Figure 21 - Wind Output, Regulation and RRS for Jan. 28, 2010



With the start-up of the nodal market on December 1, 2010, changes will be implemented in market design that are expected to greatly improve ERCOT's ability to respond to wind variability. Currently, the ERCOT operator sends energy deployment instructions for energy resources approximately 10 minutes ahead of each 15-minute interval, and these instructions cannot change until the end of the 15-minute interval. With the nodal market, ERCOT will be sending dispatch instructions at five-minute intervals, and if it detects changes in load or wind output within a five-minute interval, adjustments can be made to those instructions. It is expected that the shorter intervals will greatly improve ERCOT's flexibility and result in a reduced need for certain operating reserves, thereby reducing market operating costs that are passed on to electric customers.

System Stability

The expansion of wind energy production in Texas will bring about other reliability concerns. Wind generators historically have not contributed to stabilizing frequency following a disturbance as conventional generators do. As a result, when conventional generation is displaced by wind generation, the potential for more severe frequency disturbances increases, because the remaining conventional generation has to overcome the disturbance without help from the wind generation. However, technological improvements have brought a partial solution to this problem, and new wind turbines now come equipped with technology that allows these turbines to help restore the standard system frequency after a disturbance. New wind generators are now required by ERCOT rules to be equipped with such technology, and existing generators are required to retrofit their units if feasible.

Similarly, wind generators have not provided the quality of voltage support provided by conventional generators, support that is needed to reliably maintain the flow of electricity through transmission lines. Here again, technology is available to address this issue, and the new technology to address voltage support is now required of all new wind installations in ERCOT.

C. Storage Technologies

In most utility networks, electricity cannot be stored and energy production must match energy demand, within narrow tolerances. Electric energy storage allows the "warehousing" of electricity for later use. As the electric industry has developed renewable energy resources that are dependent on environmental forces like solar and wind energy, interest in energy storage has increased. Energy storage could assist in making higher levels of intermittent resources adaptable for use on large electricity networks.[90] Storage could provide the flexibility to adjust energy production or consumption to offset changes in wind and solar power production, allowing energy output and demand to be matched. Storage could also provide an economical means of relieving transmission constraints or meeting demand during peak periods.[91]

Benefits and Applications

Storage could provide value to an electric network in several ways. It could do more than just balance the variable nature of wind and solar resources. Storage may be able to provide the following benefits:

Energy time-shift - Electric power produced during off-peak periods when prices are low could be stored for later use or sale when demand and prices are high.

Peak shaving - Energy storage could be dispatched to meet times of high peak demand, possibly deferring or reducing the need to invest in new generation capacity.

Ancillary services - Depending on the particular technology, energy storage has the capability to respond within seconds and to provide power for short or extended periods.

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[90] Testimony of Jon Wellinghoff, Chairman, Federal Energy Regulatory Commission before the Committee on Energy and Natural Resources, United States Senate, December 10, 2009.

[91] "Energy Storage: A Critical Asset to Enable Transformation to a Smart Grid", www.electricenergyonline.com, Dan Rastler and Haresh Kamath, August, 2010.

It could, therefore, provide energy to respond to changes in load or production from power plants, offsetting the loss of generation resources or transmission capability.

Transmission support - Energy storage could improve transmission and distribution performance by compensating for disturbances on the system.

Transmission congestion - Storage could alleviate congestion by storing energy when there is no congestion and discharging energy during peak demand periods.

Defer transmission and distribution upgrades - Locating storage in an area where peak electric load is increasing and approaching the system's load carrying capacity could defer or eliminate the need for transmission and distribution upgrades. Backup power from a storage device can also give utilities the option to delay expensive upgrades in areas prone to loss of service.

Reliable power - Storage could be used to provide highly reliable power. In the event of an outage, storage could be used to meet customers' needs for the duration of the outage, facilitate an orderly shutdown process or to transfer power to on site resources.[92]

Power quality - Energy storage could quickly provide power to address voltage and frequency variations to protect customers' equipment from fluctuations in power quality.[93]

Although storage costs are, for the most part, higher than other traditional energy options, costs appear to be heading down. By performing several functions, energy storage may soon be a viable economic option for utility-scale applications.

Barriers

The hurdles storage faces are its cost and the lack of industry experience in using it in a high-voltage alternating-current network. There is little to guide industry and regulators concerning how to define storage devices and develop operational standards and compensation. While storage is capable of providing multiple services, it is difficult to assign it a role in a competitive environment, in which utilities have been unbundled. Issues relating to cross-subsidization, competition, and discrimination could arise if storage participated in multiple roles or functions at the same time. Requiring a storage facility not to perform some of the functions of which it is capable could address these concerns, but the result could be underutilization of storage devices or rendering them uneconomical.

Technology

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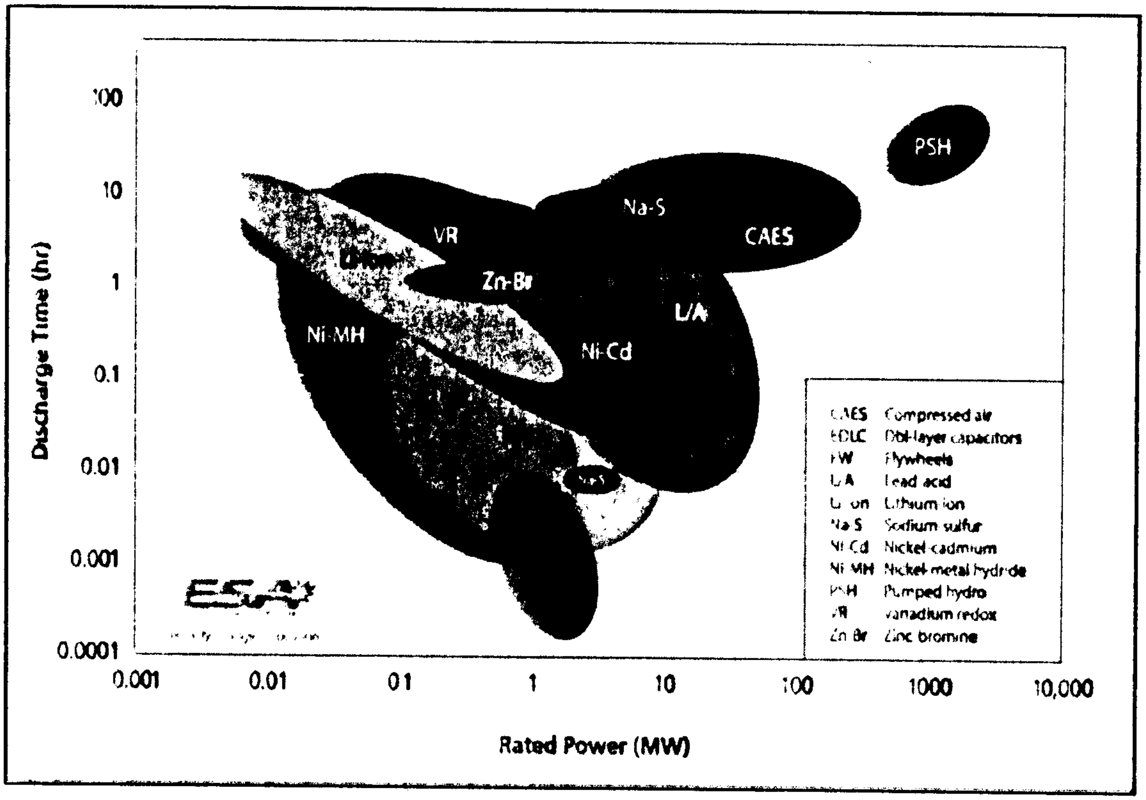
[92] Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide, Sandia National Laboratories, p. xv, xvi, February, 2010.

[93] Challenges of Electricity Storage Technologies, APS Panel on Public Affairs, p.8, May 2007.

Different storage technologies have different characteristic. Two important characteristics are the amount of energy that the storage device may deliver and the time it is able to deliver energy. Figure 23 shows the system ratings for several of the most common energy storage technologies.[94]

Figure 22 - System Ratings



Currently there are three main types of energy storage that are receiving most of the focus in the energy storage field. They are: compressed air storage (CAES), batteries, especially Lithium-ion and Sodium-sulfur (NaS), and flywheels.

CAES is a proven bulk storage technology capable of a discharge lasting 8-10 hours. In this technology, air is compressed and stored in underground reservoirs such as caverns or salt domes. As demand rises, the stored air is released through a natural gas turbine to produce electricity or is used in a combustion turbine. (Pressurizing the air is like putting a turbocharger on a combustion engine, increasing the output of the turbine.) Texas is well suited for a future CAES system. Salt domes are common and could be used to store off peak wind energy for later use when demand is high.

NaS battery storage systems have a successful operating history worldwide and in Texas. The NaS battery uses molten sodium and sulfur. It has high energy density (the amount of energy that can be stored in a given volume or mass), efficiency and long cycle life

[94] Electricity Storage Association, www.electricitystorage.org/ESA/technologies/

and can discharge up to eight hours if needed. NaS batteries offer the power and energy required for a variety of utility power system applications including voltage control, reactive power support, back-up power and deferring grid investment. Like CAES, these batteries can also be used to store excess wind power when demand is low and discharge it later to meet peak demand.

Lithium-ion batteries are used in laptop computers, and are being investigated for use in electric vehicles. Utility-level applications are emerging as research yields improvements that focus on energy density, durability, cost, and safety.

A flywheel is a mechanical battery with a wheel that spins at a high rate. When energy is needed, the flywheel can be used to provide the mechanical energy to drive a generator, but it typically has a short sustainable output period (about 15 minutes). They are presently being considered for use for load following (regulation) services.

Deployment in Texas

On March 31, 2010 Electric Transmission Texas's (ETT) four MW NaS sodium sulfur battery system was energized to the ERCOT grid. Located in Presidio, Texas, the battery is the first large scale installation in ERCOT and the largest in the United States. This NaS battery allowed the utility to defer the planned replacement of a 69 kV transmission line that is the sole source of electricity for Presidio. The battery is part of an ETT plan to improve transmission reliability in Presidio and the surrounding areas. [95] ETT expects that the battery will allow for more continuous service to the Presidio area, better response to voltage fluctuations and momentary outages, and the ability to repair the transmission line to the area without disrupting service. [96]

When the utility sought Commission approval of the Presidio battery, issues concerning ownership and control of energy storage systems were raised. The Commission ruled that:

> "ETT's proposed use of the NaS battery is appropriate for a transmission utility because the battery system provides benefits associated with transmission service operations, including voltage control, reactive power, and enhanced reliability."[97]

American Recovery and Reinvestment Act (ARRA) Funding

Recently the U.S. Department of Energy increased funding for storage projects. In 2010, the DOE granted $185 million in ARRA funds for Energy Storage Demonstration

[95] AEP news release, www.AEP.com.

[96] See PUC Docket 35994, "Application of Electric Transmission Texas, LLC for Regulatory Approvals Related to Installation of a Sodium Sulfur Battery At Presidio, Texas", p.7, August 12, 2008.

[97] See PUC Docket 35994, "Application of Electric Transmission Texas, LLC for Regulatory Approvals Related to Installation of a Sodium Sulfur Battery At Presidio, Texas", Final Order, p. 3-4, April 6, 2009.

projects in order to show the effectiveness of a range of technologies, application and deployment structures.[98] In addition, $435 million in funding was also made available for Smart Grid Regional Demonstrations of which $118 million will utilize energy storage.[99] The DOE also directed $2.4 billion in ARRA funding to promote advanced battery technology and electric-drive components. The goal is to re-establish US battery manufacturing, reduce battery cost and improve performance.[100]

ARRA funding has quickened the pace of research and development in energy storage technologies, drawing not only the participant's matching funds but intense venture capital interest as well. Due to energy storage's ability to perform a variety of applications, the world market for energy storage could grow from $1.5 billion in 2010 to an estimated $35 billion in the next ten years. Much of this growth is expected to be driven by demand from the United States.[101]

D. Plug-in Hybrid Electric Vehicles (PHEVs)

Production of electricity for household, commercial, and industrial uses historically has been one of the major uses of energy in Texas and the United States. Another major consumer of energy has been the transportation sector. Unlike the electric sector, which relies to a great extent on domestic fuels, such as coal and natural gas, the transportation sector relies heavily on crude oil produced outside of the U.S. Until recently, there was little connection between these two sectors. However, domestic and foreign automobile manufacturers have announced that they intend to begin large-scale production of electric vehicles and to begin selling them in the U.S. The initial delivery of Chevrolet Volts was expected to include shipments to Austin dealers in November, 2010. Nissan plans to sell the all-electric Leaf in Houston beginning in January 2011, and Ford has announced plans to sell a plug-in utility van in Houston in 2011 and passenger plug-in vehicles in Houston in 2012.[102]

The potential benefits of a fundamental change in the way the transportation sector is fueled include reducing reliance on a single source of primarily imported fuel (crude oil), reducing emissions of regulated pollutants in and near urban areas, and reducing

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[98] EXECUTIVE SUMMARY: Energy Storage on the Grid, Pike Research, David Link and Clint Wheelock, 3Q 2010.

[99] EXECUTIVE SUMMARY: Energy Storage on the Grid, Pike Research, David Link and Clint Wheelock, 3Q 2010.

[100] "Through ARRA, DOE trying to re-establish US battery manufacturing", www.smartgridtoday.com, May 13, 2010.

[101] EXECUTIVE SUMMARY: Energy Storage on the Grid, Pike Research, David Link and Clint Wheelock, 3Q 2010.

[102] Staff Rulemaking to Investigate Electric Market & Infrastructure Issues Relating to the Introduction of Electric Vehicles Project No. 3795, Introductory Workshop, (May, 2010).
http://www.puc.state.tx.us/rules/rulemake/37953/051210/Nissan-Presentation.pdf
http://www.puc.state.tx.us/rules/rulemake/37953/051210/Ford-Presentation.pdf

emissions of greenhouse gasses. Developing an alternative transportation fuel could pose significant challenges. The nation and the state have a broad infrastructure to distribute gasoline and diesel fuel for transportation use, but switching to a different fuel, such as natural gas or hydrogen would require a new distribution infrastructure. The electric grid is already in place, and electrification in the transportation sector is less challenging than introducing a new fuel for which the current fueling infrastructure is not well suited. Texas homes and businesses have standard (120 volt) electrical outlets that are capable of charging the plug-in electrical vehicles (PEVs) that automakers are planning to sell in Texas. The prospect of sales of increasing numbers of electric vehicles does raise a few concerns for the electric industry, however, primarily related to when and how vehicle owners will recharge their vehicles' batteries.

Near Term Issues

The Commission conducted a workshop on electric vehicles on May 12, 2010, and several near-term issues emerged concerning the coming of PEVs to Texas. One of the concerns that participants identified was the need for automobile companies, utilities, and other entities to work together to ensure a positive experience for PEV buyers and provide them information on matters like recharging options and costs. While this concern is one that primarily is the responsibility of the auto manufacturers and dealers, the utilities and retail electric providers are affected, because home charging stations could have impacts on the electric network, in a broad sense, and on local distribution facilities, and because pricing options for electricity will be more important as electric consumption increases related to vehicle charging.

Based on customers' expectations and the lack of public facilities to recharge PEVs, the expectation is that initially most PEV charging will take place at home. As demand for public charging stations emerges, public charging infrastructure will likely be developed.[103] All Texas homes with electric power have standard 120-volt outlets that will enable Level I "slow charging" of electric vehicles with a connector cord. The main drawback of Level I charging is the time needed to charge an electric vehicle battery. The Chevrolet Volt, for example, will take 6-8 hours to charge at 120 volts, and the Nissan Leaf will take up to 16 hours to charge. Texas homes will have the option of quicker Level II charging at 240 volts, but an Electrical Vehicle Supply Equipment (EVSE) unit would need to be installed to provide this level of charging, and some older homes may not have internal wiring to support a 240 volt EVSE. This EVSE equipment, in most cases, would charge the car batteries twice as fast as Level I charging. Some automobile manufacturers that plan to market PEVs in Texas are partnering with private EVSE companies to offer residential Level II EVSEs.

The Commission hosted a follow-up workshop to the initial May 12th workshop to explore any system upgrade and cost allocation issues that the transmission and distribution utilities (TDUs) might encounter in their preparations for electric vehicle charging. The TDUs believe that the main transmission infrastructure components that

[103] Characterizing Consumers' Interest in and Infrastructure Expectations for Electric Vehicles: Research Design and Survey Results, Electric Power Research Institute, 2-10 (2010).

will be affected by electric vehicle charging will be neighborhood transformers. If several electric vehicles are housed and recharged at homes in a neighborhood served from the same transformer, the transformer could be stressed. PEV charging requirements could affect transformers in two ways, increasing the use of the transformers and thus their internally-generated heat and reducing the cooling period that normally occurs at night, when other electrical uses are lower. The additional thermal load could shorten the lifespan of these transformers. While night charging of electric vehicles may be detrimental at the local level, night charging helps avoid increasing the electrical loads on the bulk electric system, which typically experiences its peak consumption hours in late afternoons. Night charging should better fit customers' needs initially, when public charging stations are not expected to be numerous or convenient to most customers. Most transmission utility representatives agree that the transmission and distribution system impacts, particularly the possibility of transformer overload, will be minimal during the *initial* phases of PEV adoption, with the possible exception of local areas there is a higher than average number of PEVs.[104]

While initially most charging is expected to be done at home, customers will want the ability to recharge quickly at public locations, and a demand is expected to grow for public charging stations. Concerns such as equipment safety and meter accuracy may require the development of national or state standards for the installation and operation of public-access charging stations. In addition, provisions of the Public Utility Regulatory Act may represent a barrier to the deployment of public charging stations in areas that are open to retail competition, because the broad definition of public utility in the Act could include the owner of a public charging station that sells electricity to owners of PEVs. Companies that are likely to operate public charging stations are not likely to choose to become public utilities, and the uncertainty of whether they could provide this service could hinder the development of public charging by utilities.

Long-Term Issues

In the long term, if the number of PEVs in use increases significantly, there are likely to be questions about how PEVs interact with the electrical network. PEVs represent an additional load on the network that will need to be met by a diverse set of resources, but they also represent a potential resource for the network that could help provide reliable service for all customers. PEVs store electricity in their batteries, and they could send electricity back to the grid when aggregate or local electricity demand is high or energy is needed to deal with system problems. These possibilities are beyond the capabilities of the first electric vehicles that auto makers are producing, but small pilot projects in other

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[104] *Electric Vehicles in Houston: Motivations, Trends, and Distribution System Impacts*, KEMA and CenterPoint Energy Whitepaper, 48 (June 23rd, 2010). This report identifies specific areas in the Houston area that are expected to have higher saturation of PEVs.

regions of the country are exploring how vehicle owners might receive compensation for supplying energy back to the electric grid.[105]

The attendees at the Commission workshop discussed the possibility of synchronizing plug-in electric vehicle charging with wind generation as car batteries, advanced metering, and smart phone technologies develop. Synchronizing wind generation with electric vehicle charging could allow plug-in electric vehicle owners in Texas to take advantage of lower price energy, because a large amount of wind generation typically occurs at night when demand from other electricity users is low. Researchers are also studying how PEVs might supply additional energy to offset a rapid reduction in output from wind farms. To achieve the synchronization of PEV charging to the grid, PEVs would have to be able to communicate with the grid and respond to signals that prices are low (because wind energy is abundant, for example) or that a problem has occurred for which the energy stored in PEV batteries could provide a solution. An advanced system of communications and control software could permit the independent electric system operator to send signals to the vehicle, which could respond by allowing the PEV's battery to charge or discharge. Thus the PEV would be responding to system conditions, based on the PEV owners' pre-selected preferences, supporting the electric system when needed and drawing energy from the electric system when energy is inexpensive. The possibility of electric vehicles giving energy back to the grid when needed is often referred to as vehicle to grid (V2G) technology.

E. Distributed Generation

Most of the resources that are envisioned as providing energy and capacity in an electrical network are large or utility-scale resources. Smaller-scale, distributed resources at customers' homes and businesses are now seen as resources that can provide several benefits, economically supplying the customer's energy needs, enhancing reliability at the home or business, and also supporting grid energy needs. Some resources, such as distributed solar energy, are also emission-free energy sources. The 1999 amendments to the Utilities Code included provisions that were intended to facilitate distributed generation (DG),[106] and the PUC has adopted rules to carry out these amendments.[107] Additional legislation related to renewable DG was enacted in 2007.[108]

Installing DG typically involves a significant up-front investment for a customer, with the expectation that the investment will pay off by reducing the customer's purchases from its retail provider, whether a utility or a competitive provider. Income tax benefits may be available for renewable DG to make an investment in such a resource more attractive. In addition, Austin Energy, the municipal utility for the City of Austin, and Oncor have

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[105] *Vehicle to Grid Technology*; University of Delaware, (2009). http://www.udel.edu/V2G/ http://www.competecoalition.com/blog/2010/10/electric-vehicles-and-smart-grid-technology-flourish-competition.

107 PURA § 39.101(b).

[107] PUC Subst. R. 25.211, 25.212, and 25.213.

[108] PURA §§ 39.914 and 39.916.

provided incentives to customers to install solar DG, and a few utilities have provided incentives for solar DG as a part of their energy-efficiency programs.

A number of issues may arise if a homeowner or business intends to install distributed generation to supply a part of the energy needs of the home or business, beyond the cost of buying and installing the facilities. These issues include:

regulatory obstacles, such as registration requirements;

difficulty in obtaining approval from the utility that serves the customer to connect the DG facility to the utility delivery system;

the cost of special metering facilities that will permit the measurement of energy that is delivered from the customer to the electric network; and

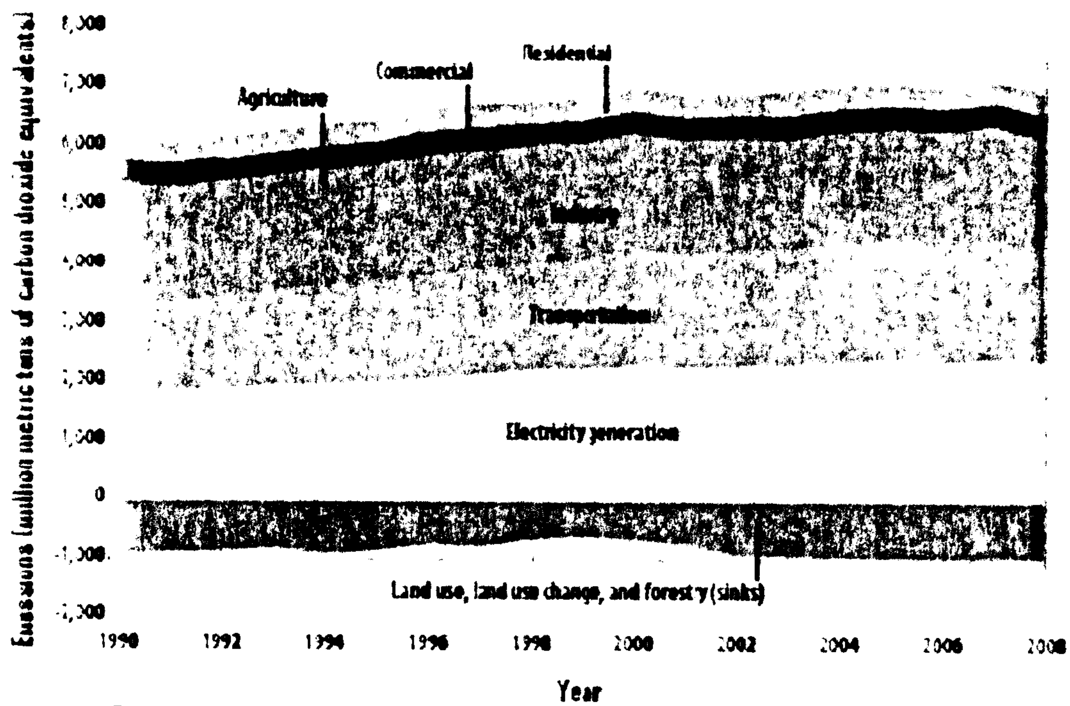
lack of opportunity to sell any excess energy that is delivered to the electric network.

F. Federal Environmental Legislation

One of the areas of regulatory and legislative activity at the national level is the possible regulation of emissions of greenhouse gasses. In addition, the U.S. Environmental Protection Agency (EPA) has a number of regulatory changes under consideration that could affect thermal generators in the U.S. According to the EPA, greenhouse gas (GHG) emissions caused by human activities in the country increased by 14% from 1990 to 2008, with carbon dioxide (CO_2) accounting for most of the emissions and most of this increase. Electricity generation is the largest source of GHG emissions in the United States, accounting for about 32% of total U.S. GHG emissions since 1990, followed by 27% for transportation. Emissions per person have remained about the same since 1990.[109]

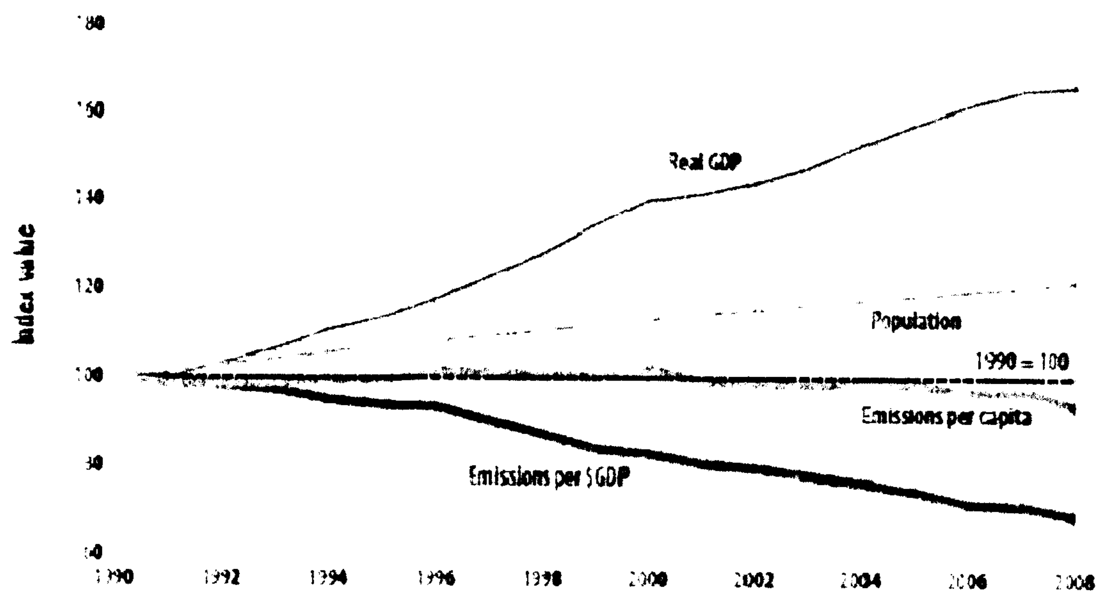
[109] U.S. Environmental Protection Agency, Climate Change Indicators in the United States, April 2010, http://www.epa.gov/climatechange/indicators/pdfs/ClimateIndicators_full.pdf

Figure 23 - U.S. GHG Emissions and Sinks by Economic Sector, 1990-2008



Data source: U.S. EPA, 2010[a]

Figure 24 - U.S. GHG Emissions per Capita and Per Dollar of GDP, 1990-2008



Data source U.S. EPA, 2010[a]

In the last few years, significant measures have been taken at the national level to monitor and report emissions of GHGs. The Consolidated Appropriations Act of 2008, enacted on

December 26, 2007, directed the EPA to develop a mandatory reporting rule for GHGs. On September 22, 2009, EPA approved final regulations requiring the monitoring and reporting of annual GHG emissions from large sources and suppliers across the U.S.[110] GHGs subject to these new requirements include CO2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons (HFCs), perfluorocarbons and other fluorinated gases. EPA estimated that the rule would cover about 10,000 facilities nationwide, accounting for about 85% of GHG emissions. The emitters must begin to monitor their emissions from January 1, 2010, with the first annual reports due in March 31, 2011.

The ARRA included $3.4 billion for carbon capture and storage projects, with $1.52 billion made available for industrial carbon capture and energy efficiency improvement projects, $1 billion for the renewal of FutureGen, and $800 million for U.S. Department of Energy Clean Coal Power Initiative Round III solicitations, which specifically target coal-based systems that capture and sequester, or reuse, CO_2 emissions. [111]

Earlier this year, the U.S. government formally associated itself with the Copenhagen Accord by committing to achieve GHG emissions reduction in the range of 17% relative to 2005 levels by 2020 "in conformity with anticipated U.S. energy and climate legislation".[112]

Greenhouse gas legislation, however, has not been enacted at the national level. In June 2009, the House of Representatives passed the Waxman-Markey American Clean Energy and Security Act (ACESA) (H.R. 2454) that would reduce GHG emissions 17% from 2005 levels by 2020 and 83% by 2050, using a cap and trade emissions trading system. Under the system, companies, including electric generators, would be granted a certain number of credits or allowances for carbon emissions. Companies that wish to exceed their emission cap could purchase unused credits from other companies that have remained below their cap. EPA estimated that implementing ACESA would cost the average household $80 to $111 per year. A similar study by the Congressional Budget Office (CBO) estimated average household cost to be $175 per year, with some lower-income households receiving a net benefit.

In April 2009, concerned about the effects of the proposed legislation on electricity prices in the ERCOT market, Chairman Smitherman requested ERCOT to perform an analysis of the impact of the ACESA "discussion draft" stating that "it is important that the PUCT and the Texas legislature have some understanding of how federal climate change legislation is likely to affect electricity consumers in ERCOT."[113] In line with a similar study conducted by the PJM Interconnection, ERCOT focused on the near-term impacts of this potential legislation. ERCOT concluded that the effect of the legislation on the

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110 http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf.

111 http://www.recovery.gov/About/Pages/The_Act.aspx.

112 http://unfccc.int/files/meetings/application/pdf/unitedstatescphaccord_app.1.pdf

113 http://www.puc.state.tx.us/about/commissioners/smitherman/reports/Bob_Kahn_Ltr_040209.pdf

typical customer's monthly bill would range from a $10 reduction to a $63 increase.[114] The state Comptroller's Office estimated that Texas could lose 170,000 to 425,000 jobs by 2030 and state GDP could decrease by $25 to $58 billion by 2030.[115]

A similar bill, the Kerry-Boxer Clean Energy Jobs and American Power Act (S. 1713), passed out of the Senate Environment and Public Works Committee, but never made it to the Senate floor. Several other bills were introduced in the Senate in 2010 to address GHGs, but none of these bills was enacted.

In the absence of comprehensive federal climate legislation, EPA moved ahead to impose mandatory controls using its existing authority. On April 2, 2007, the U.S. Supreme Court ruled that Section 202(a)(1) of the Clean Air Act (CAA) gave EPA authority to regulate tailpipe emissions of GHGs. In December 2009, the agency formally determined that GHG emissions endanger public health and welfare and therefore are subject to regulation under Section 202 of CAA.[116]

On February 16, 2010, Governor Rick Perry, Attorney General Greg Abbott, Agriculture Commissioner Todd Staples, TCEQ and PUC Chairman Barry Smitherman filed a petition with the U.S. Court of Appeals challenging EPA's endangerment finding. In addition, the state filed a petition for reconsideration, asking EPA to review its decision on the basis that it was legally unsupported because it relied on flawed science. EPA denied the petition.

In April 2010, based on its "endangerment" finding, EPA finalized mobile source emission standards which, under a CAA program called "prevention of significant deterioration", automatically triggered construction and operating permit requirements and installation of "best available control technologies" for all regulated pollutants for any new or significantly modified stationary sources, including power plants, whose potential emissions exceed 100 or 250 tons per year (depending on source type).

The Tailoring Rule[117] published by EPA in June 2010 would regulate stationary sources, such as power plants, that emit at least 75,000 tons of GHGs. In July 2012, the rule would expand to include all new facilities that emit at least 100,000 tons a year. Emissions from smaller sources will not be addressed until at least 2016.

EPA has also taken action on a number of conventional air pollutants, generally in response to the courts. The agency announced in May 2010 that it is collecting data on

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114 Analysis of Potential Impacts of CO2 Emissions Limits on Electric Power Costs in the ERCOT Region, ERCOT, May 12, 2009, http://www.puc.state.tx.us/about/commissioners/smitherman/reports/Carbon_Study_Rpt.pdf

115 http://www.window.state.tx.us/finances/captrade/txpolicies_programs/CEE_Final_Report_to_Texas_Comptroller_of_Public_Accounts.pdf

116 http://www.epa.gov/climatechange/endangerment/downloads/Federal_Register-EPA-HQ-OAR-2009-0171-Dec.15-09.pdf

117 http://edocket.access.gpo.gov/2010/pdf/2010-11974.pdf

dioxin, mercury and other emissions from utility boilers to support the proposed rule, called "Air Toxics Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source Facilities" that would set emissions standards from these sources. Under a separate proposal coal-fired power plants would be required to use the maximum achievable control technology (MACT). EPA estimates that MACT would yield health benefits of $18 to 44 billion per year at annual costs of installing and operating pollution controls of $3.6 billion. The final version of the MACT rule is expected late in 2011. The biomass industry expressed concern that the compliance cost of the new rule would be about $7 billion.[118]

In June 2010, the EPA published a final rule that would tighten the National Ambient Air Quality Standards (NAAQS) for SO_2 under the CAA, abandoning the currently applicable 24-hour and annual standards in favor of a one-hour standard. [119] The NAAQS also establish a new monitoring network for areas where SO_2 emissions coincide with high population densities. This rule will mostly affect fossil fuel power plants which account for 73 % of SO2 emissions.[120]

In July 2010, EPA proposed a final rule known as the Air Transport Rule[121] to address air emissions that cross state lines and contribute to ozone and particulate matter pollution in the eastern part of the U.S. The rule would create Federal Implementation Plans to reduce SO_2 and nitrogen oxide (NO_X) emissions from electric power plants in 32 states, including Texas, through a combination of direct abatement standards and a limited voluntary cap and trade program. The new rule would replace the Clean Air Interstate Rule of 2005 (CAIR) and require the 32 states to cut power plant SO_2 emissions by 71% and NO_X emissions by 52% from 2005 levels by 2014. The emissions reductions would start in 2012. EPA estimates annual compliance costs for the power sector at $2.8 billion and heath and public welfare benefits of $120-290 billion in 2014, including the prevention of 14,000 to 36,000 premature deaths a year. Texas was required to reduce SO_2 and annual NO_X emissions in CAIR, but in the new rule it would only be required to reduce ozone season NO_X as its SO_2 emissions do not affect other states' levels.

In the absence of federal legislation to reduce GHG emissions, state and regional programs continue to evolve. As of August 2010, 23 states accounting for 48% of the U.S. population, over 50% of GDP and 37% of GHG emissions are involved in the design of three distinct regional cap and trade systems to reduce GHG emissions. The Regional Greenhouse Gas Initiative, a cap and trade system operating in 10 Northeastern states sets a limit on CO_2 emissions at 188 million short tons per year from 2009 to 2014. This cap will then be reduced by 2.5% per year from 2015 through 2018, resulting in a cut of 10%. The Western Climate Initiative (WCI), a coalition of seven U.S. Western states and four Canadian provinces has the goal of reducing GHG emissions by 15%

118 SNL Financial LC, 2010

119 http://www.epa.gov/ttn/naaqs/standards/so2/fr/20100622.pdf

120 http://www.epa.gov/air/sulfurdioxide/pdf/20100602fs.pdf

121 http://www.epa.gov/airquality/transport/pdfs/TransportRule.pdf

below 2005 levels by 2020 across the region plans through a regional trading program set to take effect in January 2012. The Midwestern Greenhouse Gas Reduction Accord signed by six Midwestern states and one Canadian province provides for reducing GHG emissions 20% below 2005 levels by 2020. Participants commit to establish a GHG emissions reductions tracking system and implement other policies, such as two percent reduction in energy use by 2015, an increase in the percentage of gas stations offering ethanol from three to 15% and a region-wide 10% renewable energy standard.

VI. Legislative Recommendations

A. Procedural Recommendations

B. Substantive Recommendations

Appendix: Acronyms

AEP	American Electric Power
AEP TCC	AEP Texas Central Company
AEP TNC	AEP Texas North Company
AMI	Advanced Metering Infrastructure
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	SERC 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