Electricity Restructuring in Texas

A Status Report

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PREFACE

“Would you switch your retail electric provider?”

This is a question that became lawful in 1999 when the Texas Legislature devised a restructuring policy for the state’s electric power industry. After more than 100 years of service provided largely by vertically integrated, investor owned utilities or “IOUs,” the majority of Texas citizens and businesses are now fair game among competing retail electric providers.

But what is a “retail electric provider” (better known by the acronym “REP”)? For that matter, who is “the customer?” Which customers are switching, and why? And what happened to the IOUs? (They are still around, but as holding companies that include regulated transmission and local distribution grids and affiliated retail providers or AREPs; these AREPs compete, under specific rules, with new REP entrants or with each other by invading formerly sacrosanct franchise service territories.)

When California’s electric power market began to implode in 2000, industry participants, policy makers, regulators, news media, and assorted other interests around the United States focused their attention on the Texas market. As of May 2001, 23 states and the District of Columbia had passed legislation that restructured their electric power industries in various ways. Of the remaining 27 states, all but eight were in various stages of implementing restructuring programs. By March 2003, California had suspended its own program and five other states delayed restructuring. Texas was the only state to fully open its electricity market to competition, albeit with protections, following the collapse of California’s experiment and the disintegration of electricity trading precipitated by Enron’s 2001 bankruptcy and domino effect across the energy merchant sector.

Among the 18 states that have continued to push forward with electricity restructuring, Texas offers somewhat of a unique experience. Most of the state

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1 This report was prepared by the Center for Energy Economics (CEE) as the Institute for Energy, Law & Enterprise at the University of Houston Law Center (UH IELE), an interdisciplinary university research center housed within the UH Law Center. Information on the CEE and our sponsors can be obtained from our Web site, www.beg.utexas.edu/energyecon and the Guide to Electric Power in Texas, Third Edition, published with the Houston Advanced Research Center (HARC) also available from our Web site. Preparation of this paper was led by Dr. Gürcan Gülen, Research Associate, with assistance from Dr. Michelle Michot Foss, Executive Director and Assistant Research Professor, and Ms. Meg Healy, JD, Researcher. The views expressed in this paper are those of the authors and not necessarily those of others at the University of Houston and the University of Texas at Austin. Peer reviews were provided by a variety of experts.

2 Energy merchants are generally regarded as firms that engage in wholesale trading and risk management and development of wholesale (unregulated) assets, mainly electric power plants but also natural gas pipelines, storage, processing and other “midstream” facilities. They are often termed energy services businesses for the integrated solutions of energy supply, delivery, and price risk management that they offer, usually to large commercial and industrial customers.
receives electricity from a wholly intrastate grid that has only two small interconnects with the much larger grids serving the Eastern and Western U.S. The network once coordinated by the Electric Reliability Council of Texas, ERCOT, and now governed by the ERCOT Independent System Operator or ERCOT ISO remains an island. Most of Texas’ wholesale market activity is not subject to the federal regulations imposed on other interstate grid operations in the Lower 48 contiguous states (although Texas has been responsive, in many respects, to federal level changes and their implications for retail restructuring). In addition, Texans use far more electricity than the residents of any other state. Our relative isolation and market size, along with lessons learned from the restructuring experience in California and other states, makes the success or failure of the Texas program an excellent barometer for the rest of the country.

In 1995, the Texas legislature made several changes to Public Utility Regulatory Act of 1975 that would help develop a competitive wholesale market (sales of bulk electric power intended for re-sale to final retail customers). In May 1999, the legislature passed Senate Bill 7 (SB 7), which laid out a plan for restructuring the state’s retail electricity markets (sales to final customers) to allow for more competition among generators of electricity and retail sales of electric power through customer choice. Full implementation of SB 7 through the Texas Electric Choice program began on January 1, 2002.

An important component of Texas Electric Choice is the public education campaign undertaken by the Public Utility Commission of Texas (PUCT). Researchers at the CEE, then known as the Institute for Energy, Law & Enterprise (IELE) at the University of Houston Law Center have assisted the PUCT in this endeavor. In May 2001, shortly before the pilot program began, we issued *Electricity Industry Restructuring in Texas: A White Paper* (available at [www.powertochoose.org](http://www.powertochoose.org)).

That paper was an independent review of the final policy actions contained in SB 7, how the law would be implemented, and some potential costs, benefits and challenges. In January 2003, CEE published the third edition of *Guide to Electric Power in Texas* in conjunction with the Houston Advanced Research Center (HARC). The *Guide* is a detailed primer on the Texas electric power industry and national issues and trends and can be downloaded free of charge from our Web site, [www.energy.uh.edu](http://www.energy.uh.edu).

CEE researchers also have investigated dynamic pricing opportunities for small commercial users in Texas (with less than one megawatt, or MW, of peak demand). We have twice surveyed (in March 2002 and March 2003) REPs and aggregators, the new market participants created by SB 7, to solicit their concerns about the Texas model and their assessments of the emerging marketplace. We hosted a roundtable discussion on January 31, 2003 involving stakeholders who represented many different perspectives, with a follow up discussion on May 30, 2003. We have monitored our own student population at UH (because of our older demographic, many UH students are electric power customers) to sample levels of retail

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3 Note that our 2001 research paper was undertaken as the Energy Institute, Bauer College of Business.
participation. We have pursued these activities while also monitoring competitive electricity market experiments in elsewhere in the U.S. and in other countries, exploring issues like capacity schemes, zonal-nodal pricing alternatives and price caps, as well as broader, best practice issues in restructuring electric power industries. Our work to understand the Texas case, events in California, and how the two situations compare and contrast has been published in locations such as Brazil and Turkey and is used in an international training program, *New Era in Oil, Gas & Power Value Creation*, offered through the CEE.

This paper, *Electricity Restructuring in Texas: A Status Report*, is an assessment of the Texas experience with a competitive retail electricity market 18 months into implementation, based on data as of May 2003 and monitoring through summer 2003. Our paper reflects input from many diverse market participants (REPs, aggregators, generators, utilities, consumers, and regulators). Our work targets the ERCOT region, which comprises roughly 85 percent of the total electric power market in Texas, and which constitutes a third and separate electric power grid in the United States (the other two being the Eastern and Western interconnects). As noted later in this report, retail competition has not been implemented in portions of the state of Texas which lie outside ERCOT.

**EXECUTIVE SUMMARY**

The process of restructuring the Texas electric power industry and system to create a competitive retail market is being watched closely by industry analysts, regulators and legislators from other states, as well as the federal government and governments of other countries. At stake is no less than the future of electricity competition in the U.S., both in terms of whether there will be competition as well as the shape and nature of other emerging power markets among the states and at the federal level.

From this perspective, the first couple of years of the Texas experience (starting with the summer 2001 pilot program) yielded mixed results. Some commentators have declared Texas Electric Choice “a mistake”\(^4\) while others claim that the new market regime works and that the Texas model is one of the best in the world.\(^5\)

In this status report, we provide some statistical measures used by the PUCT and others to assess the progress of competition. We also discuss the most frequently identified problems experienced thus far by the Texas market participants as well as several remaining challenges.

From statistical data gathered as of May 2003 to provide a market “snapshot” and anecdotal evidence, it is apparent that large users (more than one megawatt or MW) are shopping for competitive contracts and generating significant savings (from tens of thousands to a million dollars). Wholesale electricity prices have

\(^4\) For example, see “Admit it, Texas, electricity deregulation a mistake” by Tim Morstad, a policy analyst for the Southwest Regional Office of Consumers Union, December 9, 2002, *Houston Chronicle*.

\(^5\) For example, see the Alliance for Retail Markets (ARM) and the Center for the Advancement of Energy Markets (CAEM) comments, discussed later in the paper.
declined, primarily due to excess supply, more efficient generation, and a slowing economy (although higher prices for natural gas, an important fuel source for power generation, have shaved some of this benefit). At the retail level, the state-mandated utility rate reductions (price-to-beat) that were incorporated into SB 7 also have generated savings.

In contrast, small users (residential and commercial consumers with less than one MW of peak demand) are not switching electricity providers in significant numbers, and their savings are limited at best. Publicity about switching and billing problems may have discouraged these small, “core” customers. To the extent that fuel cost adjustments associated with higher natural gas prices have eaten into consumer savings, many consumers view competitive rates as rate increases that contravene the rate decreases many proponents of competition promised them and implemented. (Pass through of higher natural gas cost is done with PUCT approval by the affiliated retail electric providers or AREPs, REPs that are part of holding companies formed out of the former investor owned utilities). In many cases, smaller customers simply have not been able to detect adequate savings from switching to be attracted to the Texas Electric Choice program. Recently, retail providers began competing more aggressively on price, offering rates 15 to 20 percent below the rates of AREPs, especially in metropolitan areas.

Most of the transition problems, such as delays in switching and new connections and duplicate billings, have been of a technical nature. The pilot program helped regulators and market participants discover and mitigate some, albeit not all, of the technical shortcomings of the systems put into place by the ERCOT ISO. Some contend that a longer pilot would have solved more problems. In retrospect, though, given the significant changes that have been made and the need for new information systems and personnel training by almost all market participants, it is doubtful that all of these problems could have been addressed completely during the pilot. In addition, the pilot did not reflect full-scale open competition, as only five percent of retail customers were allowed to choose their electricity provider. Thus, a longer pilot may not necessarily have addressed problems associated with the substantial ramp up of potential participants in a fully open retail market.

Inefficient market structure and market manipulation were more significant issues. The PUCT, through its Market Oversight Division (MOD), quickly modified procedures to address such behavior and disciplined the companies that took advantage of gaps in the market design. Yet, a number of opportunities for gaming remain. The MOD constantly monitors market behavior and, where possible, recommends modifications to fix perceived problems and distortions. However, some market participants (retail providers, transmission and distribution providers, schedulers, customers or other) may perceive the MOD’s own actions as interference with the marketplace and hence distorting to the competitive benefits expected from the market. In general, given the increased political sensitivity towards electricity restructuring following the California crisis and overlapping scandals in energy trading, it probably is wise of the PUCT to avoid highly

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6 We refer here to the general collapse across the energy trading businesses and associated “merchant” activities (development of unregulated, competitive natural gas and electric power assets
publicized price spikes and volatility that could be attributed to unethical or improper behavior by the energy companies, especially in the early years of the competitive market. Importantly, actions by the MOD and PUCT, in combination with particular strategies embedded in SB 7 (such as the decision to allow bilateral contracting arrangements) have moderated the Texas program, yielding a more conservative approach than more aggressive retail market designs in other states and nations. This should be kept in mind as progress in Texas is measured and evaluated.

Remaining challenges are significant but probably do not threaten Texas’ competitive restructuring over the long run. Excess supply resulting from the expansion of electric power generation capacity (mostly natural gas-fired) by almost 22 gigawatts (GWs) between 1995 and early 2003, roughly 20 percent of new capacity in the country, led to lower electricity prices especially after the U.S. and Texas economies slowed down in 2001 and 2002. Although good news for customers, low prices hurt the finances of most energy companies that are still trying to recover from collapse of the energy merchant sector. Without investment in new generation capacity, demand will eventually catch up with and may even surpass supply. The market tightness and high prices that would result in that case could be harmful to market evolution. The success of competition depends on suppliers keeping up with demand increases over the long run, as signaled by market prices, and having financially sound competitors in different segments of the market.

The dilemmas associated with capital formation and investment in generation capacity also apply to transmission infrastructure. The August 14, 2003 blackouts that affected roughly 50 million customers in the upper Midwest and Northeast\(^7\) drew attention to the quality and extent of transmission networks across the U.S., and also to the uniqueness of the ERCOT marketplace given its relative isolation. Within ERCOT, however, a number of transmission constraints exist. Additional transmission capacity is being sought to accommodate rapidly developing wind capacity in West Texas. Texas has been recognized for adoption of a “renewable energy portfolio standard,” an approach to encouraging private investment in alternative energy technologies and projects. One question is how the expense incurred to build new transmission capacity to dispatch electricity from these projects should be allocated across Texas customers, and whether other incentives are needed to encourage transmission investment for wind projects in remote locations. Additional transmission capacity also is needed to avoid congestion in various parts of the state. A market approach to assigning the costs of congestion (in essence, a pricing scheme that reflects peak demand for transmission capacity and risk management), following the December 2001 bankruptcy filing by Enron Corporation. This included sharp downgrades in credit ratings, shuttered trading floors, and a consequent reduction in market “liquidity,” i.e., the loss of participants and financial transactions to support the wholesale market.

\(^7\) The August 14, 2003 blackout remained under investigation as this paper was issued. For information on progress in understanding the causes of the blackout, the reader can refer to the Office of Electric Transmission and Distribution at the U.S. Department of Energy, http://www.electricity.doe.gov/.
subject to transmission capacity constraints) must be resolved in the near future in order to facilitate proper signals for private investment.

Although the issues and challenges we discuss do not comprise an exhaustive list, we believe they represent the most immediate concerns expressed by a variety of market participants. Undoubtedly, there are other concerns, especially in the technical arena, but these should be easier to resolve based on the experience gained during the past couple of years.

Overall, the competitive Texas Electric Choice program is moving forward fairly competently. Excess supplies put into place during the past couple of years allowed the PUCT and ERCOT, as well as market participants, to address many issues without risking sustained price spikes. Indeed, compared with experience in other parts of the U.S., one lesson might be that when creating new market structures, timing is everything. Large users are saving significant sums. But the potential outcome of retail competition for small users remains to be seen, and whether lack of results in terms of numbers of participating customers hampers the overall restructuring effort. Of concern also are natural gas supply and price trends. Natural gas generates more than 60 percent of electricity in Texas. If a $4 to $5 per MMBtu (million Btu or British thermal units, a measure of heat content) price range for natural gas becomes the norm, as opposed to the $2 to $3 per MMBtu range of the past, electricity in general will be more expensive and new REPs, which depend largely on gas-fired power, may have difficulty competing in the market.8

INTRODUCTION9

In the United States, industries characterized by strong, technical networks such as airlines, telecommunications and natural gas have experienced varying degrees of restructuring beginning in the late 1960s and extending through today. The goal has been to make these industries more competitive and responsive to market forces. These reforms have yielded an array of positive results, most notably lower prices, a vast assortment of new technologies, widespread innovation and a greater array of products and service options to customers. The experience gained from restructuring other heavily regulated network industries supported the broad effort to open the electric power industry to competition.

Traditionally, most consumers in metropolitan areas obtained their electric power from vertically integrated, investor owned utilities that build large power plants to generate electricity, long-distance high-voltage transmission lines to ship electricity from the central generation plants to consumption (or load) centers, and dense, low-voltage distribution networks to deliver electricity to consumers (end users).

8 With respect to timing for new market structures, we should note that much of the impetus for electricity restructuring in the U.S. stemmed from chronically low natural gas prices during the 1990s and the notion that gas-fired power, in particular, could compete effectively in open, wholesale power markets. CEE researchers write and speak frequently on natural gas issues in Texas and the U.S. For example, see testimony by Dr. Michelle Michot Foss to the U.S. House Subcommittee on Resources, June 19, 2003, http://resourcescommittee.house.gov/108cong/energy/2003jun19/agenda.htm.

9 The information in this section is a re-cap from Guide to Electric Power in Texas, third edition. See www.energy.uh.edu, publications, to download the Guide free of charge.
Since the late 1800s and early 1900s, IOUs in Texas and across the U.S. have operated as monopolies in designated franchise service areas, free of competition but with prices set by regulators in exchange for obligations to serve the public interest. IOUs faced no direct competition within their service territories, but their rates were regulated by state public utility commissions10 – like the PUCT – on the basis of the utilities’ costs to generate or purchase, transmit and distribute electricity. This arrangement is called “cost of service regulation” and acts as a substitute for open, competitive pricing of electricity.

In May 1999, the Texas legislature passed Senate Bill 7 (SB 7) to restructure the electricity industry. In summer 2001, Texas launched a pilot program designed to test the waters for replacing the monopoly-cost of service regulatory system with a competitive retail electricity market. The pilot program authorized up to five percent of the state’s retail electricity customers to choose a retail electric provider (REP) other than the provider affiliated with their traditional utility. In January 2002, all Texas retail electricity customers were eligible to choose their electricity provider.

Transmission and distribution services remain largely within the purview of the traditional utilities, but the transmission grid is now operated by a new entity, the ERCOT independent system operator. ERCOT, one of the 10 regional reliability councils that comprise the North American Electric Reliability Council or NERC (see Appendix 2), previously served to coordinate voluntary cooperation by the state’s utilities in ensuring transmission system reliability. Under the Texas restructuring plan, ERCOT now is responsible not only for reliability of the transmission system but also for ensuring non-discriminatory access to this system.

ERCOT serves about 85 percent of the Texas electricity load. Some portions of the Texas load are served by neighboring reliability councils – the Southwest Power Pool (SPP; Texas Panhandle and part of East Texas), the Southeastern Electric Reliability Council (SERC; Beaumont area) and the Western Systems Coordinating Council (WSCC; El Paso region).11 These councils do not enjoy the isolation from federal regulation that the almost fully intrastate ERCOT does. The electricity loads located in the SPP and SERC service territories were opened for retail competition along with ERCOT loads on January 1, 2002; however, these regions have not yet implemented retail choice programs.12

Other key components of Texas’ electricity restructuring plan include:

10 City governments in Texas have the authority to regulate end user electric power prices. With the establishment of the PUCT, most municipal governments refer all rate cases for private, regulated entities to the state, maintaining rights to intervene and participate. Utilities that are owned and operated by municipal governments are also regulated by those governments. In addition, municipal utilities and cooperatives were allowed by the Texas Legislature to “opt in” to Texas Electric Choice. Many chose not to participate. Other states have similar exceptions.

11 For details, please see the map in Appendix 2 and Guide to Electric Power in Texas.

12 In fact, the timing and process of these regions eventually joining the competitive market presents a major issue, but, in this paper, we will focus on the ERCOT region and the issues that were raised during the first two years of retail competition in this region.
• Utilities must unbundle their generation, regulated transmission, and distribution and retail service operations;
• Utilities may not own and control more than 20 percent of installed generation capacity within ERCOT;
• Generators must reduce their nitrogen oxide and sulfur dioxide emissions from “grandfathered” power plants within a two-year period after the formal market opening;
• Generators must triple the amount of power they supply from renewable resources – e.g., small hydro, wind and solar power – by January 1, 2009.
• Municipal utilities and cooperatives may choose whether or not to open their service territories to competition;
• AREPs must reduce the rates they offer to small users (residential and commercial consumers with less than one MW of peak demand) by six percent from their rates in effect in 1999. This will be their price to beat (PTB) until January 1, 2007, or until the AREP loses 40 percent of the customer base within its franchise service territory to competitors, whichever happens earlier.
• AREPs may adjust their PTBs twice a year to reflect fluctuations in the price of natural gas.

According to the Center for the Advancement of Energy Markets (CAEM), among many others, the competitive retail electricity market in Texas is actually one of the best in the world. With a grade of 69 out of 100 in CAEM’s 2003 Retail Energy Deregulation (RED) Index, the Texas market certainly is not a flawless performer, but it ranks third after two markets restructured in the early 1990s – England which scored 88 and New Zealand which scored 75. Pennsylvania scored 67, trailing Texas.13

In January 2003, the Alliance for Retail Markets (ARM), a group of competitive electricity providers, heralded the first year of the Texas Electric Choice program as a success citing, in particular, “higher than expected” switching levels.14 The PUCT also seems satisfied with the market’s performance in its first year, pointing to a total savings of $1.5 billion, high switch rates by large users (in terms of both numbers of users and volume of demand) and significant number of competitors (see next section for PUCT data).

However, the market also experienced some problems. In particular, switching and billing problems associated with delays at ERCOT and among transmission and distribution service providers (TDSPs, which remain under cost of service regulation

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13 CAEM is nonprofit organization founded in 1999 to promote market-oriented solutions to challenges that confront the energy industry and other network industries. For details of CAEM and its RED Index, please visit www.caem.org.

implemented by the PUCT) received the most publicity. In the main, it was the inability to manage an increased amount of information flow efficiently that resulted in most delays. Critics also pointed to the lack of interest among small customers in shopping for electricity and increases in AREP rates associated with fuel cost adjustments as indications of a failed market.\textsuperscript{15} 

In addition, there have been few incidents of gaming. Although the PUCT addressed these incidents in a timely manner, its MOD is diligently pursuing a number of potential flaws in the market design that may allow for similar manipulation (see Appendix 1).

Other issues and challenges include maintaining system reliability while expanding the grid capacity, establishing generation adequacy standards, uncertainty about natural gas prices, managing congestion, stranded cost recovery process, concerns about the financial health of certain market participants and ERCOT governance. Although none of these problems or issues appears to be a “deal killer,” they require attention for the continuous and healthy development of the Texas market.

\textbf{STATISTICAL SUMMARY OF THE FIRST YEAR OF TEXAS ELECTRIC CHOICE}

One year after opening Texas’ electricity market to competition, the PUCT estimated that retail customers had saved more than $1.5 billion in electricity costs, as compared to the regulated rates in effect during 2001. In addition, it estimated that the System Benefit Fund had saved low-income customers another $70 million through October 2002.

The PUCT also reported to the Texas legislature that, in all areas open to competition, multiple REPs – up to 10 in some areas – offer service to all customer classes, and an increasing number of customers are exercising their opportunity to choose an electricity provider.\textsuperscript{16}

\textbf{Savings}

In an effort to guarantee some savings under regulated utility rates, the Legislature required AREPs to grant residential and small commercial customers a six percent discount from their tariff rates in effect on January 1, 1999. This established a price to beat (PTB) for non-affiliated REPs. In May 2001, we projected that the mandated six percent reduction would result in total savings of $988 million, as compared to the utility’s regulated rates in effect from 1999 to 2001 (see Table 1, last column). The PUCT’s analysis of actual REP charges for 2002 indicates that the state’s electricity customers saved at least $1,547 million in the first year of Texas’ restructured electricity market.

\textsuperscript{15} For examples, see footnote 4 and “Electricity Providers' Rates Vary Widely in Fort Worth, Texas, Area” by Dan Piller, \textit{Fort Worth Star-Telegram}, March 31, 2003.

\textsuperscript{16} \textit{Scope of Competition in Electric Markets in Texas}, Public Utility Commission of Texas, January 2003, available for download at \url{www.puc.state.tx.us/electric/reports/scope/index.cfm}.
Most of the savings (58 percent) occurred in the **residential sector**. In May 2001, we projected that residential customers would save $443 million from the mandatory six percent discount alone. The PUCT, however, estimates that only $225 million of the $902 million in residential savings is due to the mandatory six percent rate reduction built into the PTB. The rest reflects lower fuel costs and the expiration of fuel surcharges.

### Table 1. Savings in 2002 compared to 2001 rates ($ million)

<table>
<thead>
<tr>
<th></th>
<th>390 (Oncor)</th>
<th>386 (CenterPoint)</th>
<th>68 (CPL)</th>
<th>44 (TNMP)</th>
<th>14 (WTU)</th>
<th>902 (Total)</th>
<th>443</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential PTB Savings</td>
<td>420</td>
<td>297</td>
<td>225</td>
<td>248</td>
<td></td>
<td>1,547</td>
<td>988</td>
</tr>
</tbody>
</table>

The PUCT also estimates that residential users who switched to REPs with rates lower than the AREP’s saved an additional $11 million. These savings could have been a little higher except for the residential customers who switched to REPs providing renewable electricity at rates higher than most other offers, including that of AREPs. This group is estimated at five to ten percent of total residential switchers.

Note that the two most populous areas of the state – Dallas-Ft. Worth (Oncor franchise territory) and Houston (CenterPoint franchise territory) – enjoyed about 86 percent of the residential savings. Not surprisingly, these two areas also enjoy more competition. In each of these territories, ten REPs, including one affiliated with the established utility, offer 11 products (including two renewable products) to accommodate customer preferences. By comparison, seven REPs operate in CPL’s (Central Power and Light) territory, five in TNMP’s (Texas New Mexico Power) territory and three in WTU’s (West Texas Utilities) territory.

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17 While calculating our $443 million estimate, we included all residential customers in ERCOT, including those in cooperative and municipal utility territories that did not opt in so far. There are also a number of residential customers who switched providers since the market opening. Hence, it is normal for our estimate to be larger than the PUCT figure of $225 million.

18 For service territories, please see map in Appendix 2, which is taken from Guide to Electric Power in Texas.
Based on the lowest prices offered (available at [www.powertochoose.org](http://www.powertochoose.org)) during 2002, the PUCT calculated that residential consumers could have saved an additional $636 million if they all had switched to the lowest current offer available in their area. Figure 1 is based on offers available in May 2003 and reflects the price to beat offered by the AREPs (in this case, Reliant and TXU) vs. the cheapest REP offers in the CenterPoint (Houston) and Oncor (Dallas-Ft. Worth) territories. In May 2003, there were roughly 1,443,000 households in CenterPoint’s territory, and each could have saved $0.0165 per kWh by switching to the REP with the lowest rate offer. Assuming an average monthly consumption of 1,200 kWh per household, total annual savings would have been roughly $347 million. Similarly, if all 2,237,000 households in the Oncor territory had switched to the REP with the lowest rate, saving $0.0125 per kWh, total annual savings would have been roughly $450 million. In sum, the residential consumers in these two metropolitan areas could have saved a total of $797 million – a 20 percent increase from PUCT’s estimate of $636 million from late 2002. Obviously, these numbers reflect a best case scenario and not actual conditions. All residential consumers are not able to switch to the lowest-cost provider, as this entity probably could not serve all of a region’s customers, but once switching starts, the potential competition should drive other offers down as well. In spring 2003, we started to witness this phenomenon for the first time in Oncor’s territory as most REPs did not match TXU’s fuel cost adjustment increases.\textsuperscript{19}

**Small commercial users** (less than one MW in peak demand) benefited from similar PTB savings. **Large commercial and industrial (C&I) users** (more than one MW in peak demand) also benefited by negotiating long-term contracts with AREPs and REPs. Although the information in these contracts is proprietary, the PUCT was able to generate the estimates shown in Table 1 based on the data reported by REPs to the Energy Information Administration (EIA). Anecdotal evidence we collected indicate savings for large users ranging from tens of thousands of dollars per year to as high as one million dollars per year for a statewide retail chain.

Some of the savings by C&I users reported in Table 1 was generated by 18 aggregation groups, including political subdivisions such as school districts and municipalities. Aggregation savings are estimated at $134 million by the PUCT. .

\textsuperscript{19} As noted earlier, however, by not passing on higher fuel costs to customers, REPs risk financial losses.
In our May 2001 report, we projected savings of $297 million for commercial consumers and $248 million for industrial users, based on the assumption of a six percent discount. Combined with residential savings, we projected total annual consumer savings of $988 million, as compared to PUCT’s current estimate of $1.5 billion. Assuming that the PUCT number is accurate, it is clear that large users have been able to save significantly more than six percent when signing competitive contracts.

**Switching**

To level the playing field for non-affiliated REPs, the Legislature, in SB 7, required AREPs to charge their price to beat for five years (until January 1, 2007), or until 40 percent of each customer group selected an alternative REP, whichever happened earlier. Many market observers view the slow pace of residential switches as an indication of residential customers’ lack of interest in shopping for electricity, and thus the limited effect of competition in residential markets. Figure 2 summarizes the switching patterns of residential users (indicated by R) and small commercial users (indicated by C) as well as loads for small commercial users (indicated by megawatthours, MWh) in five major TDSP territories during 2002.

![Figure 2. Percentage of Small Customers Served by a Competitive REP](image)

*Source: February 2003 Report Card on Competition, PUCT.*

**Residential switching** is still low although there is a slight upward trend in most TDSP areas. Most notably, almost 10 percent of customers in CenterPoint’s territory (i.e., mainly Houston) and seven percent in Oncor’s territory (Dallas-Ft. Worth) were served by a competitive REP in December 2002, as compared to less than five percent during the first half of the year. In other regions, less than five percent of customers switched. The level of switching by Oncor’s residential customers (Oncor R) roughly reflects the average switching rate for residential...
customers in Texas. The low switching rate should have been expected. Most residential consumers are not used to shopping for electricity; for many, the savings (per household) do not provide sufficient incentive; and some probably experienced concerns after the California crisis and problems in the energy trading sector. Finally, low electricity prices probably erased some of the already low incentives\(^{20}\) for bargain shopping. This pattern of slowly rising interest in switching was observed in other restructured markets, most notably in the UK market.

**Small commercial switching** is attracting somewhat more interest. The levels of switching by CenterPoint’s commercial customers (CenterPoint C) roughly reflects the average for this group. The percentage of commercial customers served by a competitive REP rose from less than one percent in January 2002 to 11 percent by December 2002. In CPL’s territory, more than 14 percent were served by competitive REPs in December 2002. More than 30 percent of the statewide load was served by a competitive REP in December 2002. This indicates that larger commercial users switched suppliers. In CPL’s territory, more than 45 percent of the small commercial load was served by a new REP while 40 percent of the commercial loads in WTU’s and TNMP’s territories were served competitively.

More recent PUCT data indicate that the upward trend of switching rates for both residential and small commercial users continued in the first half of 2003.

**Large commercial and industrial switching**, on the other hand, occurred in much larger quantities, especially with respect to load. Figure 3 indicates that the

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\(^{20}\) In the May 2001 report, we calculated total annual savings for an average household consuming 1,200 kWh a month at around $78 based on PTB. With lower wholesale prices, this already low incentive was probably further eroded.
percentage of large users served by a competitive REP increased from about five percent in January 2002 to roughly 19 percent by the end of 2002. In terms of load, about 50 percent of these customers have been served by non-affiliated REPs since February 2002. This ratio seems quite healthy for competition given the fact that electricity prices remained quite low during 2002. Large users who entered into long-term contracts benefited significantly by protecting themselves from increases in natural gas, and hence electricity, prices in the second half of the year. Also, large users benefited from competition by negotiating contracts with AREPs that included lower prices or preferred service terms. Their savings are estimated in the range of 15 to 30 percent. According to the PUCT, the percentage of these large users with a competitive contract rose from about 50 percent in January 2002 to about 95 percent by early 2003. This also bodes well for the continued development of healthy competition.

Problems Experienced

Beyond statistics, the market has not progressed smoothly. The pilot program in the summer of 2001 was delayed twice by almost two months mostly due to system problems at ERCOT. Once the pilot started, even with only five percent of customers allowed to switch, there were significant delays in registering the switches, and the lack of customer interest was probably a blessing. Perhaps more importantly, there was gaming and price spikes. Repeated fuel cost adjustments, although mostly justified by rising natural gas prices, also drew attention from consumer advocates and the press.

The problems of the competitive electricity market in Texas fall into two main categories: 1) market-related issues, such as gaming and price spikes, and 2) technical problems, such as switching delays and multiple billing.

Market-related Issues

Gaming

Currently, ERCOT uses a zonal model for congestion pricing with four congestion zones – South, Houston, North and West – because there are three commercially significant constraints. The ERCOT ISO manages congestion between zones through re-dispatch of the system and assignment of congestion charges. ERCOT auctions transmission congestion rights (TCRs) for financial rights on the commercially significant constraints.21

In August 2001, some market participants over-scheduled in known congestion zones, causing price increases in the balancing market. The estimated cost of these manipulations was roughly $45 million. PUCT’s rules concerning congestion charges allowed companies to pass these costs on to customers. These rules were later changed. In particular, direct assignment of zonal congestion costs was implemented in February 2002. Accordingly, the companies that cause congestion

21 For details of the congestion management approach in Texas, visit www.ercot.com.
now must pay for it. See the section on congestion management, below, for a discussion of additional modifications being reviewed by the PUCT.

For the August 2001 incident, the PUCT investigated six companies, pursued cases against five of them and settled four of the cases out of court. The companies were qualified scheduling entities (QSEs) that scheduled power across the state’s four transmission zones. Mirant, American Electric Power, TXU, Constellation Power Source, and Reliant Energy Inc. all claimed that the manipulation was unintentional. According to the PUCT’s MOD, "the market rules that were then in effect resulted in significant revenue to these QSEs when their actual loads in the congested zones were lower than their scheduled loads." The companies generated an estimated $1 million to $3 million each in additional revenues.

Although the PUCT took disciplinary action and changed transmission protocols to resolve this early case of market manipulation fairly quickly, these mitigation measures were not sufficient to discourage the hockey stick bidding suspected to have contributed to the price spike of February 24 and 25, 2003 (see next section).

On the other hand, the MOD has shown that almost none of the infamous games Enron and others played in California\(^\text{22}\) can be played in Texas,\(^\text{23}\) but has identified 13 potential manipulation opportunities (see Appendix 1).

**Price Spikes**

On February 24 and 25, 2003, the balancing market (five to ten percent of the market) experienced price spikes of $990 per MWh for 28 fifteen-minute intervals. Extremely cold temperatures, high natural gas prices and technical problems at some plants resulted in the substantial supply shortfalls reflected in the price spikes. Natural gas prices had been rising since December 2002, and they spiked to almost $19 per MMBtu on February 25, 2003, the same day the electricity price spiked (see Figure 4). In certain locales, gas prices rose to $25-33 per MMBtu. Natural gas curtailment plans monitored by the Texas Railroad Commission were put into effect. Under these plans, residential users had priority access to natural gas. Also, pipeline pressures were low and may not have been sufficient for some generating units. As a result, gas supplies to electric generators were reduced.

The PUCT estimated that, under these conditions, a price of $250 per MWh would be normal\(^\text{24}\) but it also detected “hockey stick” bidding, i.e., extremely high bids for very small amounts of power. In tight market conditions, the need to buy

\(^{22}\) For example, Export of Power, Load Shift, Death Star, Get Shorty, Fat Boy, Ricochet.

\(^{23}\) These games were designed for California’s market rules and electric grid. Unlike California, Texas has a bilateral market design and allows market participants to self-supply ancillary services. For details, see *Enron’s Wholesale Power Trading Strategies in California*, Public Utility Commission of Texas Market Oversight Division, June 18, 2002.

\(^{24}\) However, on February 24 and 25, the availability and price of additional fuel were unknown to generators. Some generators were not able to operate and others were forced to use fuel (including oil) from their inventories. Under these circumstances, the spot price of natural gas is not the only factor in determining the marginal cost of power; the cost of carrying fuel inventories and starting up units have to be taken into consideration as well.
electricity from the balancing market rises. In these situations, companies can sell small amounts at very high prices. ERCOT protocols allow for this bidding behavior. However, these high prices may have a disproportionate impact on the financial stability of other market participants that have not adequately covered their market price risk. For example, Texas Commercial Energy was a fairly successful REP, but overexposed to the balancing market in February 2003. The high prices it had to pay for the electricity it needed to serve its customers forced the company into Chapter 11 bankruptcy. About 80 of its large customers, in turn, were forced to contract with the provider of last resort (POLR) for service, at much higher prices. Most of them switched to other competitive providers eventually. TCE filed a lawsuit in July against ERCOT alleging that the ISO is unduly influenced by market players and affiliates of Reliant, TXU, American Electric Power and Mirant manipulated the market.\textsuperscript{25}

The Market Oversight Division (MOD) included hockey stick bidding in its list of gaming opportunities prepared in 2002 (see Appendix 1). As a mitigation measure, the MOD proposed Competitive Solution Method (CSM). February spikes expedited the assessment of this method, which was not universally accepted by market participants. Reliant Resources Inc. and City Public Service Board (CPSB) submitted alternative proposals to the Commission after the February 24-25 spikes. At the end of August 2003, the PUCT adopted a modified version of CSM developed by the staff to accommodate concerns of various participants about the original CSM. According to the modified method, the market price of balancing energy will be set at the 95 percent level of the bid stack, discarding extremely high bids.\textsuperscript{26}

\textsuperscript{25} For details, please see “Texas marketer’s ERCOT lawsuit tells grisly tale,” Restructuring Today, July 15, 2003.

\textsuperscript{26} For details, please refer to the PUC Docket No. 24770, available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/24770_262_405449.PDF.
In addition, on March 21, ERCOT approved a resolution that requires all load-serving entities to meet at least 90 percent of their daily average load obligations through contracts or their own generation and not depend on the balancing energy market to meet their needs.

As a result of these measures, both the incidences of extremely high prices in the balancing market and the overexposure of REPs to these prices (e.g., TCE’s exposure in February) should be minimized.

**Increases to PTB**

The pro-competition messages delivered to residential consumers with the Texas Electric Choice roll out focused on the mandated six percent rate discounts to be reflected in each AREP’s price to beat. Accordingly, many consumers remain unaware that this mandated discount applies only to the non-fuel components of retail electricity rates. Twice a year, however, AREPs may request fuel cost adjustments that reflect changes in wholesale fuel prices. So as fuel prices rise, these fuel cost adjustments can raise retail electricity rates in spite of the discount – in some cases, even above 1999 levels. The two largest AREPs in the state, TXU and Reliant, as well as others, received approvals for fuel cost adjustments in summer 2002 and winter 2002-2003, which translated into price increases for retail consumers. **Natural gas price increases were the main reason for these fuel adjustments.** As shown in Figure 5, the price of natural gas had indeed risen significantly in both periods, especially during the winter of 2002-2003.²⁷

²⁷ Figure 5 is truncated on purpose at $7.50 per MMBtu in order to render other price movements more visible.
Historically, natural gas prices have generally remained below $2.50 per MMBtu. After hovering below $3 per MMBtu between September 2001 and February 2002, gas prices averaged about $3.50 per MMBtu from March 2002 through May 2002. Residential consumers, who for the most part did not show much interest in switching and signing long-term contracts with other REPs, were left paying these higher prices. Consumer groups expressed their concerns regarding these price hikes to the PUCT.

Recent increases in gas prices are of concern to other market participants as well. Since 60 to 70 percent of Texas’ electricity is generated in gas-fired plants, gas costs comprise a significant component of the state’s electricity prices, and thus the future of electricity competition.

More important, however, are the potential for savings and the overall long-term trend of electricity prices in a competitive market. In 2002, when AREPs adjusted their fuel charges upward, competitive REPs usually raised their prices as well, keeping their discounts from AREP rates at about 10 percent. After the most recent fuel cost adjustments in early 2003, however, many REPs kept their rates constant or increased them to a lesser degree than the AREP. Most significantly, Reliant’s REP (the second largest electricity provider in the Dallas-Ft. Worth area) reduced its rates after initially raising them in tandem with TXU’s rate. These are encouraging signs of increasing competition among REPs for small customers.

To illustrate the impact of Texas’ retail electricity restructuring on an individual household, we consider the actual experience of one of our colleagues, who lives in Houston. Figure 6 tracks his monthly average unit cost for electricity – i.e., his

![Figure 6. A Sample Electricity Bill](image-url)
total bill (not just energy charges)\textsuperscript{28} divided by his total kWhs consumed. Our colleague is an average Texas household and consumes about 1,200 kWh a month.

Prior to November 2001, Houston Lighting & Power – the electric utility subsidiary of Reliant Energy that existed before restructuring – sold power to our colleague at its regulated cost-of-service rates. From November 2001 to July 2002, he purchased electricity from NewPower – a REP owned in part by Enron. After NewPower filed for bankruptcy in July 2002, the PUCT assigned his account to TXU.

In general, our colleague’s electricity rates rose following the demise of NewPower, but the NewPower rates reflected here incorporate refunds for overcharges arising from a settlement with the PUCT. Also, as natural gas prices started to increase in the second half of 2002, his cost of electricity also increased, albeit at a slower pace. It is useful to note that price offered by the competitive REP has been significantly lower than the AREP’s PTB. Although this single observation is not proof of anything in itself, it is consistent with reports of more competitive pricing strategies by REPs in major metropolitan areas.

Overall, his cost of electricity from competitive providers has been lower than most of his HL&P era costs, despite the historically high price of natural gas since mid-2002. This is probably due to the availability of excess supply in the market and level of competition among providers during the same period.

\textit{Technical Problems}

Most of the technical problems associated with restructuring are the result of the increased complexity of transactions and the number of players that need to

\textbf{Figure 7. Initiating a Customer Switch}

1. Customer signs with Retailer

2. Retailer sends switch request & ERCOT acknowledges

3. ERCOT sends switch notification to customer

4. Customer can cancel the switch within 3 business days

Source: ERCOT

\textsuperscript{28} Note that the TDSP (transmission and distribution) charge would be the same for all providers, affiliated or non-affiliated. Any REP moving power through Houston will use CenterPoint wires, charges for which are regulated by the PUCT.
communicate customer data to each other every time a customer switches from one REP, or AREP, to another, or changes physical location.

Since switching electricity providers is a new activity introduced by restructuring, there is also a learning curve that all participants involved in the switching process had to climb. The complexity of the process probably made the learning more difficult and time-consuming. Since restructuring began in Texas, at least three types of entities are now responsible for exchanging information pertaining to customer switches: the retail electric providers (REPs), the transmission and distribution service provider (TDSP) and ERCOT independent system operator (see Figures 7 and 8).

**Switching Delays**

Commencement of the pilot program itself was delayed for two months, until July 2001. ERCOT’s system delays continued after the January 1, 2002 opening of the

**Figure 8. Completion of Customer Switch**

1. Utility reads meter
2. Utility sends meter data
3. ERCOT completes switch
4. ERCOT forwards final meter read to Retailers

Source: ERCOT

**Figure 9. Percentage of Switches Completed Successfully**

<table>
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<tr>
<th>Month</th>
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</thead>
<tbody>
<tr>
<td>Mar-02</td>
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<td>Oct-02</td>
<td>100%</td>
</tr>
<tr>
<td>Nov-02</td>
<td>100%</td>
</tr>
</tbody>
</table>

Source: Data Responses filed in Project No. 24462.
market, but appeared to be resolved for the most part by summer 2002 (see Figure 9). As late as November 2002, five to ten percent of switches were still being delayed. As of this writing, some REPs, aggregators and customers still complain that TDSPs still have problems with timely delivery of key information.

**Billing**

The main problems with billing include delays in receiving bills, multiple billing and missing bills. Figure 10 below represents the complex set of transactions that must take place before any retail provider can generate a customer’s bill.29

![Figure 10. Customer Bill Calculation](source)

In addition, as switching and registration of new move-ins are delayed, billing also delayed. Although the number of customers missing bills declined from over 250,000 in early 2002 to around 65,000 by the end of 2002 and the percentage of move-ins completed successfully has stabilized above 95 percent, a number of customers continue to have problems and file complaints with the PUCT. Partly as a result of bad publicity associated with these problems, the promotion of retail choice among residential consumers remains an uphill battle. The REPs and aggregators we surveyed and interacted with over the last couple of years were also concerned about persisting switching and billing problems as well as the resulting bad publicity (see Appendix 3 for their perspectives).

29 For details on Figures 7, 8 and 10, please visit [www.ercot.com](http://www.ercot.com).
REMAINING CHALLENGES

Our research highlighted several additional challenges to the healthy development of competitive markets in Texas.

Generation and Transmission Adequacy

Throughout 2002, the newly restructured Texas electricity market had too much supply. Interestingly, this is likely the result of the initial appeal of the Texas model, which attracted construction of 55 new plants with a total capacity of roughly 22 GW since 1995. In addition, demand did not increase as fast as once thought, mainly due to an economic slowdown beginning in 2001. Although the resulting fall in wholesale prices is good news for consumers, the merchant builders of power plants failed to generate the revenues they needed. For a segment of the industry that has been hurting since the California crisis and trading scandals, these additional financial shortcomings have been quite damaging. As a result, several merchant generators have shut down some of their power plants – comprising several thousand megawatts of generation capacity in total.

Although Texas still has a comfortable reserve margin (almost 40 percent according to ERCOT’s May 2003 report to North American Electric Reliability Council), ERCOT had to keep some of these plants as reliability-must-run (RMR) units because of their locations on the grid. Their absence could have caused significant reliability or congestion problems during peak hours. Obviously, decommissioning of older, more expensive and dirtier plants is one of the desirable results of competition, but ERCOT’s reliable operation of the transmission network may not allow all of these retirements unless a suitable substitute is built at the right location on the grid.

The excess supply situation probably will delay the construction of new generation capacity in the short-run, potentially creating tight market conditions over the next several years. Financially challenged companies will wait for significant price increases before building new generation facilities.

Another problem is the lack of price transparency, as more than 90 percent of electricity traded in Texas is through private, bilateral contracts. The price signals from the balancing market indicate a market heat rate\(^{30}\) of 7 Btus per MWh to 8 Btus per MWh. Under these circumstances, only the most efficient plants (e.g., combined cycle gas units or cogeneration units) would be commercially viable. Investors are unlikely to build the generation capacity necessary to secure high reserve margins using these efficient technologies, especially given the high gas price environment and the challenges the industry is facing in raising capital. The MOD’s proposed approach of requiring affidavits from generators to ensure marginal cost pricing also may be a major obstacle to formation of market price signals for new generation.

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\(^{30}\) Heat rate is a measure of generating station thermal efficiency. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net generation. Market heat rate is calculated by dividing market price of electricity with market price of natural gas (in most markets, the marginal fuel), which provides an indication of what efficiency power plants should be run (or built).
Despite Texas’ high reserve margin at present, ERCOT is concerned enough about healthy reserve margins over the long run that it is considering models similar to capacity markets (where capacity – as opposed to energy - can be traded) used by the ISOs in the Northeast and models based on some kind of a reserve margin requirement. Most market participants, though, remain opposed to mandatory reserve margin limits.

We note that with improvements in wholesale market conditions and financial solvency of the operators, many distressed generation plants likely will come back on line (or the assets will eventually turn over to companies that can operate them profitably).

However, it is important to emphasize that a constraint for merchant generators remains the relative isolation of the ERCOT grid. Although, post-August 14 blackout, it may seem like customers within ERCOT benefit from that isolation, it does, in fact, cut both ways. Surplus power cannot be moved out of the ERCOT region, limiting the options available to generators and marketers (as well as customers located outside of ERCOT in adjacent regions). Likewise, customers or aggregates of customers that could benefit from competitive generation built outside of ERCOT have no access to that capacity. Nor are ERCOT customers completely protected from blackout or brownout events. While ERCOT has not had a major disruption in reliability, on par with the event of August 14, since the competitive wholesale and retail markets have been created, transmission and generation constraints within ERCOT have contributed to smaller scale disruptions that have tested vigorously system reliability.

For ERCOT to evolve larger interconnections with other grids in the U.S., a number of factors will need to be put into place. Most important will be a transition toward common standards for transmission investment and operation across the U.S., which means, in turn, a shift toward interstate commerce as a priority for electric power and a lessening of state control. This is a highly controversial arena in electric power policy today. In 2002, the Federal Energy Regulatory Commission or FERC, which oversees the wholesale market at the national level, proposed a scheme for standard market design that, in the opinion of many, would lead to larger, more efficient and seamless market areas for electric power; reduce the costs and barriers associated with electric power transfers over greater distances; lead to improved incentives for transmission investment; and help to increase the competitiveness of the wholesale market. The FERC envisioned four large regional systems – Northeast, Southeast, Midwest and West, with ERCOT constituting a fifth region transmission organization. The FERC’s proposal met with immediate dissension and controversy. Indications are that without supporting legislation from the U.S. Congress, which would address issues raised by state jurisdictions (public utility commissions, legislatures and governors) and consumer groups, the FERC’s proposal for common market standards will not be finalized and implemented.31

31 The CEE has prepared a review of national electricity issues which addresses the FERC proposal and related concerns and considerations in more detail. For more information, contact energyecon@beg.utexas.edu or access www.beg.utexas.edu/energyecon for information regarding public release.
As to transmission capacity within ERCOT, additional investment hinges on financial health of the market participants that would ordinarily invest in new transmission grid and related facilities and rules implemented by the ERCOT, with PUCT oversight, for congestion management. Both of these issues are addressed below.

**Financial Health of Market Participants**

The situation with respect to excess generation capacity and distressed assets in Texas is not the only problem faced by many of the entities that build and operate new, competitive power plants within the state and ERCOT. Some of the companies operating in Texas also are being investigated for market manipulation in California and elsewhere as well as roundtrip trading and other improprieties. In addition, some of the remaining merchant entities, most of which are or were affiliates of investor owned utilities or regulated natural gas pipeline companies, have been exposed to market risk abroad, especially in Latin America and Europe.

As a result, most companies have lost both revenue and market value, with some individual stocks downgraded to below investment grade. Although, many sold assets, including domestic assets, at a loss to improve balance sheets, most equities analysts expect this situation to continue until at least 2005. Because so many of the energy merchant companies were affiliates of investor owned utilities, the crisis in this segment was a drag on the electric utility industry in general, as parent corporations took actions to stem losses (including reducing or eliminating their merchant businesses, both in trading and related activities, and with regard to investment in new assets). A consequence of all of this is that timing of new generation and transmission capacity additions may not be commensurate with rising levels of demand likely to be experienced in Texas in the coming years.

**Congestion Management**

ERCOT’s choice of congestion management methodology will have cost implications for the entire system. Currently, ERCOT uses a zonal model with four zones: South, Houston, North and West (because there are three commercially significant constraints within the grid). ERCOT manages congestion between zones through re-dispatch of the system and assignment of congestion charges. ERCOT auctions transmission congestion rights on these constraints. This approach fails to address intra-zonal congestion problems because the costs of relieving intra-zonal congestion are allocated to all loads. Since locations of congestion constraints may change over time and since there is no hedging mechanism available to manage

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32 For example, Duke Energy estimates that losses associated with their electric power trading and merchant operations in Texas and the U.S. have totaled roughly $1 billion (comments from company officials and based on corporate financial data available at [www.duke-energy.com](http://www.duke-energy.com)).

33 A definitive review of the financial meltdown and lost market capitalization in the energy merchant sector was Moody’s Special Comment, May 2002, *Moody’s View on Energy Merchants: Long on Debt—Short on Cash Flow, Restructuring Expected, Summary Opinion*.

34 The Dow Jones electric utilities index peaked at roughly $175 at the end of 2000 and had lost more than half of its value by the fourth quarter of 2002. Index trends available at [www.bigcharts.com](http://www.bigcharts.com).
transmission cost risk, buyers and sellers may be reluctant to enter into long-term contracts for transmission capacity.

Among the alternatives currently under consideration is nodal pricing, commonly known as locational marginal pricing (LMP). LMP is used in the PJM territory (Pennsylvania-New Jersey-Maryland) and is recommended as a model for Regional Transmission Organizations in the FERC’s proposed standard market design for competitive electricity markets. Adopting a nodal approach to congestion pricing may improve system efficiency and reliability. It also may send more accurate price signals not only for congestion management but also for siting new generation and transmission facilities. Most directly, however, a nodal system is expected to reduce local congestions costs. The PUCT staff estimated that local congestion costs were $218 million in 2002 and $50 million in the first quarter of 2003.

But implementation costs for LMP may be high. Cost estimates for the information management systems that would be required at the ERCOT control center and scheduling entities range from $25 million to $50 million each. The PUCT staff estimated the net present value of the costs between $130 million and $140 million in the first five years, and between $255 million and $265 million in the first ten years for all entities that would be impacted by the implementation of a nodal system. Overall, the PUCT staff expects the net benefit of the nodal system to be between $320 million and $445 million in the first ten years in present value terms.

There are also concerns that LMP may increase the cost to loads and decrease the potential savings margin between PTBs and retail provider rates where there is local congestion. Finally, the possibility of increased gaming opportunities is a concern.

Alternative approaches to congestion pricing have been proposed. The Lower Colorado River Authority (LCRA) model calls for advance identification of constraints that the market could effectively deal with through the creation of load zones around these constraints. Then, instead of unit-specific bids with nodal settlements (as would be the case under an LMP approach), LCRA proposes portfolio generation bidding with full zonal settlement. Critics of the LCRA model point out the difficulties of defining congestion ahead of time, allocating local congestion costs and, similar to LMP, absorbing an estimated $100 million in implementation costs.

The PUCT has been reviewing the costs and benefits of these alternatives and is expected to reach a decision in 2003. The key seems to be finding the least cost, most feasible methodology for determining local congestion costs and allocating those costs efficiently and as equitably as possible within the ERCOT marketplace.

Even with a solution to congestion management, and introduction of an accepted scheme for pricing congestion, there are questions regarding PUCT’s authority (or lack thereof) to order construction of additional transmission capacity and associated landowner rights and royalty payments. Consideration is being given to whether PUCT can allow the construction of private use transmission lines without

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the traditional evaluation of proposals through the certificate of convenience and necessity process.\textsuperscript{36}

\textbf{Transmission Expansion for Wind Power}

A particular transmission capacity issue concerns the expansion of the grid to accommodate new wind power projects. Since the passage of SB 7, which called for 2,000 MWs of new renewable capacity by 2009, about 1,000 MWs of new wind power capacity has been built in the western part of the state. But transmission capacity between West Texas and consumption centers in the central and eastern portions of the state is insufficient to serve this new load. The construction of new transmission lines will be costly and a cumbersome process. ERCOT estimated the cost of upgrading the transmission system to accommodate wind farms to be $150 million. ERCOT also estimated that the costs will at least double if all of the renewable sources mandated in SB 7 were to come from wind power in West Texas. SB 7 includes language such that these costs should be spread among all consumers, not just those who sell or buy wind power. Many customers, in particular large commercial and industrial users that are particularly sensitive to incremental costs, object to this approach.

In addition, there is some question as to whether wind generators should be allowed to receive their production tax credits or renewable energy credits. Naturally, these credits should be collected only when electricity is dispatched, but without new transmission lines, these isolated wind power generators cannot dispatch all of their generation.

\textbf{Stranded Costs}

Before electricity markets are restructured, stranded costs – investments made under regulation but not fully recovered by the time the market opened for competition – have to be dealt with. In Texas, SB 7 allowed for the recovery of all net, verifiable, non-mitigated stranded costs through a competition transition charge.

However, the calculation of the asset values under the category of stranded costs is dependent on the time the calculation is made.\textsuperscript{37} The PUCT’s calculations reflected this volatility – finding several billion dollars in stranded costs before 2000 and negative stranded costs (or benefits) in 2001. This dramatic reversal of stranded cost calculations resulted primarily from the high cost of gas-fired generation, precipitated by abnormally high natural gas prices (see discussion of Price Spikes, above). The resulting higher electricity prices allowed coal-fired and nuclear power plants to remain competitive and to earn more value from selling their generation into the market than would have been feasible under regulation (and than was expected in the post-SB 7 world when initial stranded cost estimates were

\textsuperscript{36} For details of the certification process for new transmission facilities, see \textit{Guide to Electric Power in Texas} or visit www.puc.state.tx.us.

\textsuperscript{37} Stranded costs are calculated as the present value of the difference between regulated revenues and market revenues.
compiled). To return negative stranded costs (or benefits) to consumers, the PUCT established an excess mitigation credit. Retail providers affiliated with utilities such as TXU and Reliant challenged the mitigation credit in court. In a settlement the PUCT allowed TXU to recover $1.3 billion in return for TXU’s agreement to seek no further stranded cost recovery. The PUCT continues to question the value of assets reported by utilities as a result of the accounting irregularities, market manipulation and price fluctuations that have plagued the industry.

The PUCT will hold a hearing in 2004 to make a final determination of total stranded costs. If the PUCT decides during this “true-up” hearing that a utility has over-recovered stranded costs, any competitive transmission charges can be stopped, mitigation can be reversed, and/or transmission and distribution rates can be lowered. Also in 2004, the difference between the price-to-beat that an affiliated retail provider has charged and the prevailing retail market price of electricity will be reconciled. This is meant to capture profits the affiliated provider has accrued if the price-to-beat is above market. This amount will be deducted from remaining stranded costs. The true-up process is likely to be contentious and may have an impact on competitiveness ability of retail providers that are affiliated with utilities.

**Provider of Last Resort and Bad Debt**

Early on, during both negotiation of final language in SB 7 and the first stages of implementation, consumer groups were concerned about the “POLR” or provider of last resort design, which called for significantly higher rates for those customers that are delinquent in paying their electric power bills and who are subsequently dropped by their retail providers. (Customers in these circumstances who fail to pay their POLR bills risk termination of electricity service.) There were also issues regarding which provider would operate as POLR in any given area. Although originally POLR rates were set high to discourage customers from falling into the POLR service, the PUCT modified the rules and lowered the POLR rates, acknowledging consumer concerns about those customers who fail to pay their bills for legitimate reasons.

On the other hand, the current POLR arrangement may be creating incentives for customers to withhold payment to REPs or POLRs, returning them to their local affiliated retail provider by default. REPs are concerned that this behavior seems to be increasing not only among residential customers, but also among small commercial customers. Although some of the non-payments are due to billing problems and delays, some customers appear to be switching and avoiding payments deliberately. It is apparent that some of this behavior is associated with customers switching from provider to provider to take advantage of discounts while leaving behind delinquent bills (consumers in these situations may not be aware of, or are choosing to ignore, the impact of this behavior on their credit histories, with a further complication that some REPs, in particular smaller, new start up companies, may be unable to obtain adequate credit information on new customers). Furthermore, some customers simply do not pay the default AREP service. The PUCT tried to address this problem by allowing AREPs, as well as POLRs, to disconnect customers who do not pay their electric bills. By 2004 or
2005, all REPs may be given the right to disconnect non-paying customers, a privilege they do not have at present (but which is retained by AREPs).

**Qualifying Generation Facilities and PURPA**

A fundamental conflict exists between the federal Public Utility Regulatory Policy Act of 1978 (PURPA), which created qualifying facilities (QFs) and required utilities to buy their electricity from QFs at avoided cost, and SB 7, which opened the Texas electricity market to retail competition. In the Texas market today, integrated utilities no longer exist (that is, the original IOUs have become corporate entities that hold regulated transmission and distribution companies and unregulated, competitive, affiliated retail providers with functional separation as required by law, with the intention of reducing or eliminating conflicts of interest). Nearly all generation is supplied by non-utilities. Yet, AREPs inherited their affiliated utilities’ long-term purchase obligations with QFs. To the extent these lingering QF obligations restrict AREPs’ flexibility with regard to wholesale or bulk purchases of power for re-sale to final, retail end users, they may limit the competitiveness of AREPs, especially outside of their incumbent service territory. AREPs may have to buy more expensive QF power from time to time to meet these contractual obligations.

A consideration for how the PUCT deals with this issue in terms of modifying AREP obligations to purchase power from QFs is whether the U.S. Congress decides to repeal PURPA. It is not clear whether Congress will take this action and when repeal of PURPA might take place. A clear consequence for AREPs with QF obligations is the impact on the price to beat formula. However, the price to beat is a transitional element, due to be phased out by 2007 or when the AREP gives up 40 percent of its market to competing REPs. In this situation, without PURPA repeal and if QF obligations are still in force, either the AREPs in question lose competitive advantage or all retail providers increase prices to take advantage of an inherent premium in the marketplace.

**ERCOT ISO Governance**

Many of the remaining issues in the restructured Texas market, or at least in that portion of the market that constitutes the ERCOT system, represent arenas of high conflict among market participants. From the outset, ERCOT ISO staff and managers and PUCT commissioners and staffs, with close monitoring by the state legislature and outside organizations such as ours, embarked on SB 7 implementation as a full stakeholder process. Texas is a unique state in which to experiment with electric power restructuring – it is strong in consumer protection traditions as well as having a widely perceived “business friendly” environment. Across all ISOs and regional transmission organizations in the U.S., however, issues have arisen indicative of a particular problem in restructuring to build new, competitive markets: what are the best methods of organizing these third party

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38 For details, see *Guide to Electric Power in Texas* available at [www.energy.uh.edu](http://www.energy.uh.edu).
system organizations in order to provide governance structures that ensure level playing fields and ethical conduct?

The ERCOT ISO governance structure requires scrutiny in order to ensure that the ISO continues to serve all market participants in a fair and transparent manner. The lawsuit filed by Texas Commercial Energy against the ERCOT ISO regarding the ISO’s role during the February 24-25 spikes that forced TCE to file for bankruptcy challenges ERCOT’s independence from market players. The lawsuit points to the type of issues surrounding the debate on ERCOT ISO governance.
### Appendix 1

#### Summary Table: Mitigation Measures for Gaming Opportunities in ERCOT

<table>
<thead>
<tr>
<th>No.</th>
<th>Problem</th>
<th>Effect</th>
<th>Market Impact</th>
<th>Frequency</th>
<th>Mitigation</th>
<th>Implementation Date</th>
<th>Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Creation of artificial congestion</td>
<td>Party receives payment for relieving congestion it created</td>
<td>Increases market operations costs</td>
<td>Difficult to assess, but has resulted in high costs</td>
<td>Direct assignment of local congestion costs</td>
<td>Spring 2003</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Misrepresentation of schedules</td>
<td>Receive load or resource imbalance credit</td>
<td>Increases costs to other market participants</td>
<td>Occurred in August 2001</td>
<td>Direct assignment of zonal congestion costs</td>
<td>Was implemented in February 2002</td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>Bid a few MW at maximum price (hockey stick bidding)</td>
<td>When struck, brings in large revenues</td>
<td>Price spikes</td>
<td>Every interval</td>
<td>When bid stack is short, use alternative method for price discrimination</td>
<td>Spring 2003</td>
<td>1</td>
</tr>
<tr>
<td>4</td>
<td>Physical withholding through manipulation of Resource Plan information</td>
<td>Make generation unavailable and raise prices</td>
<td>Higher prices</td>
<td>Frequent</td>
<td>Require binding Resource Plan</td>
<td>No date for Protocol change initiation at this time</td>
<td>1</td>
</tr>
<tr>
<td>5</td>
<td>Unrestricted deviation and private chasing</td>
<td>Receive resource imbalance payment</td>
<td>Increases costs and need for frequency controls</td>
<td>Frequent</td>
<td>Increase penalty Pay ex-post price to remove price chasing incentive</td>
<td>Was partially addressed in June 2002</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Spring 2003</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Building large blocks of power at high prices only (Economic withholding)</td>
<td>Creates short supply of reasonably priced bids</td>
<td>Price spikes</td>
<td>Frequent</td>
<td>Public disclosure of high bids Use alternative method for price discrimination</td>
<td>July 2002</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Spring 2003</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>When instructed to generate by ERCOT, understate units planned operating level</td>
<td>Receive higher payment from ERCOT</td>
<td>Increases costs to other market participants</td>
<td>Frequent</td>
<td>Direct assignment of local congestion costs Require binding Resource Plan</td>
<td>Spring 2003</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>No date for Protocol change initiation at this time</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Bidding small amounts of power from several units in Replacement Reserve market</td>
<td>Supplier receives multiple start-up costs</td>
<td>Raises cost of Replacement Reserves</td>
<td>Occasional</td>
<td>Add Protocol requirements to bid whole units</td>
<td>Protocol change to be initiated July 2002</td>
<td>2</td>
</tr>
</tbody>
</table>

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39 Presentation of the Public Utility Commission of Texas to the Electric Utility Restructuring Legislative Oversight Committee, June 18, 2002.
<table>
<thead>
<tr>
<th></th>
<th>Event Description</th>
<th>Impact Description</th>
<th>Frequency</th>
<th>Solution Description</th>
<th>Date</th>
<th>Severity</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>When selected for Replacement Reserves, do not start unit</td>
<td>Receive payment for no service rendered Increases costs to other market participants</td>
<td>Occasional</td>
<td>Pay only upon verification through telemetry</td>
<td>July 2002</td>
<td>2</td>
</tr>
<tr>
<td>10</td>
<td>Misrepresentation of On/Off status of plant</td>
<td>Receive undeserved start-up cost payment Increases costs to other market participants</td>
<td>Occasional</td>
<td>Verify on-line information through telemetry</td>
<td>July 2002</td>
<td>2</td>
</tr>
<tr>
<td>11</td>
<td>Physical withholding through outage manipulation</td>
<td>Make generation unavailable in order to raise prices Higher prices</td>
<td>Not detected to date</td>
<td>Require ERCOT coordination of planned outages</td>
<td>Not considered at this time</td>
<td>2</td>
</tr>
<tr>
<td>12</td>
<td>Price reversal in A/S market</td>
<td>Higher payment received for low level A/s Shortage of bids for higher level A/S</td>
<td>Infrequent</td>
<td>Discontinue sequential selection of A/S and go to simultaneous selection</td>
<td>December 2002</td>
<td>3</td>
</tr>
<tr>
<td>13</td>
<td>Holding back A/S bids</td>
<td>Can sell at higher price when second market opens Higher prices for A/S</td>
<td>Not seen to date</td>
<td>Do not use market clearing price, base price on 80% of requirement Settle each market separately</td>
<td>Implemented Fall 2002</td>
<td>3</td>
</tr>
</tbody>
</table>
Appendix 2
Maps

North American Electric Reliability Council (NERC)

Texas Interconnection
ERCOT: Electric Reliability Council of Texas
WECC: Western Electricity Coordinating Council

Eastern Interconnection
ECAR: East Central Area Reliability Coordination Agreement
MAAC: Mid-Atlantic Area Council
MAIN: Mid-America Interpool Network
NAPP: Mid-Continent Area Power Pool
NPCC: Northeast Power Pooling Corporation
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
FRCO: Florida Reliability Coordination Council

General Locations of Investor Owned Transmission and Distribution Utility Service Areas
Appendix 3
Perspectives from REPs and Aggregators

For retail electricity competition in Texas to succeed, we need a sufficient number of competitors who have profitable retail businesses. In order to assess their perspectives on the evolution of the Texas market, we surveyed REPs and aggregators twice, once in early 2002 and again in March 2003, and held a roundtable discussion in January 31, 2003 with many of them participating. Overall, we were able to reach 8-10 REPs and 8-10 aggregators each year. The following is a summary of their reactions to some of the questions we posed.

Overall assessment of the Texas market

Perhaps not surprisingly, both in 2002 and 2003, we received mixed responses. Some were satisfied with the market as they were able to sign customers and generate profits while others were struggling. There were also few who went out of business.

Nevertheless, most pointed out to technical problems discussed above. Some suggested that the switching, billing, and data transfer problems, which challenged most REPs and aggregators in establishing their businesses, could have been mainly worked out during the pilot, if the market open was delayed.

There were also concerns about AREPs inheriting all the customers, the failure of “Chinese walls” between incumbent PGCs and AREPs, and the lack of education on the part of consumers.

Overall, however, most showed optimism about the future of the market.

Overall assessment of REP/Aggregator business

Neither of these businesses has so far generated decent profits for most of the participants. Margins have been too thin and competition has been tough. Niche players with either aggressive marketing or energy services mentality or serving certain groups of customers (schools, hospitals, churches, municipalities, etc.) have been more successful. Consolidation is likely to increase margins in the future.

Difficulties in acquiring customers

Although quite a few REPs and aggregators did not report any difficulties, many cited ERCOT’s technical delays (switching, billing, etc.) and general lack of interest on the part of customers (due to apathy, ignorance, and fear & distrust resulting from bad publicity – California crisis, Enron’s collapse and trading scandals) as main obstacles in signing new customers.

Contract complexities (especially those between REPs and aggregators) and difficulties in conveying price differences to customers were also mentioned.

Another concern was the influence of the incumbent utilities on some customers mainly due to strong historical relationships, some at the board level. These customers were said to be reluctant to change suppliers for fear that they would be harmed financially.

Experience with ERCOT

Although some did not report any difficulties with ERCOT, many cited billing problems, switching delays, and confusing TDSP charges as very important problems. Some REPs wanted to render ERCOT accountable for technical problems that lead to financial impact on their operations.
Most also agree that ERCOT improved significantly. However, it took so long to fix problems in data transmission from the TDSPs to the retailers resulting in bad bills that some customers have been lost and others have decided to stay put with the Price to Beat. Some attributed most of the blame to TDSPs rather than ERCOT, however, as they were seen as delaying the information flow.

**Experience with PUCT**

Most of the REPs and aggregators did not report any specific problems with the PUCT and some praised the regulator’s performance. However, some complained about PUCT’s inaction on several complaints they filed with the agency. Some of the issues raised were: no standards regarding contracts between REPs and aggregators, no enforcement of rules concerning data of PTB bills and customer’s access to data to verify bills, and the complexity of TDSP charges. Finally, the PUCT was seen as too involved with the "market participants" excluding customers.

**Major issues and challenges**

Customer acquisition remains a concern for many REPs and aggregators mainly due to continuing technical problems (billing and switching) associated with ERCOT and/or TDSPs, and the customers’ lack of interest mainly due to confusion, uncertainty, distrust and lack of access to usage data.

On the market side, opening up of non-ERCOT areas such as Entergy and territories of munis and coops are of concern to some REPs and/or aggregators.

Also, the uncertainty about the evolution of prices once 40 percent of the market load shifts from AREPs to competitors (or the time limit expires) concerns some. Especially with the natural gas prices much higher than their historical averages, the price competition will be tough.