Lessons Learned: The Texas Experience

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Abstract

The wholesale electricity market of the Electric Reliability Council of Texas (ERCOT) has operated as a single control area for more than two years following an approximately two-year design phase. The current market in ERCOT differs from the Federal Energy Regulatory Commission's Standard Market Design (SMD) and from other electricity markets in many aspects. This paper presents a description of the ERCOT market and of the lessons drawn from the Texas experience from August 2001 to April 2003.

1. Introduction

Electricity market reform has taken place over the last 15 years in various countries. There are more than a dozen existing restructured electricity markets in the United States and around the world[1]. The markets vary in terms of the market organization, system operation, transmission charges, congestion management, and investment incentives. These differences are often related to the history of the particular system, asset ownership, operational practices, and philosophical perspectives. Some markets have a day-ahead market for spot trading while some others have just a day-ahead scheduling process together with a short-term market to facilitate real time operations.

Because of various difficulties and problems experienced, each market has changed in some aspects. Some markets have undertaken big changes, such as in the California market and the England and Wales market. The California market ended its zonal Power Exchange and is implementing “MD02,” which is similar to the Federal Energy Regulatory Commission’s (FERC) Standard Market Design (SMD). The England and Wales market changed from a centrally dispatched bid-based power pool to the New Electricity Trading Arrangements (NETA) based on bilateral trading in a forward market and a balancing market. Other markets, including that of the Electric Reliability Council of Texas (ERCOT), have changed more incrementally.

This paper presents a review of the electricity market in the ERCOT system and draws lessons from the experiences. The main focus is on the ERCOT market design and its development after July 31, 2001 until approximately April 2003. The conclusions should be tempered with the understanding that the restructured ERCOT market has been in place for only about two years, so that some conclusions can only be tentative at best.

This paper is based on a variety of reports, filed comments of stakeholders, and the records of workshops related to wholesale market design at the Public Utility Commission of Texas (PUCT) from 2001 to 2003. The information resources are: the Commission’s *Reports on the Scope of Competition in Electric Markets* to the 77th Legislature (PUCT, 2001c) and to the 78th Legislature (PUCT, 2003a), the white paper (PUCT, 2002d), the report (PUCT, 2003b) and the presentations in workshops of the ERCOT wholesale market design project (PUCT, 2002b), the ERCOT protocols (PUCT, 2000), the comments of stakeholders in response to Commission’s questions about day-ahead markets (PUCT, 2002c), congestion management issues (PUCT, 2003c), and lessons learned (PUCT, 2002k).

The organization of the paper is as follows. Section 2 is an overview of ERCOT, beginning with a brief history of legislation, market milestones, and statistics and then continuing with an overview of the market design. Section 3 describes and assesses in detail the components and characteristics of the ERCOT market. Comparisons to other markets are made and the changes to the market structure will be discussed. Where appropriate, lessons will be drawn from the Texas experience. Section 4 summarizes the lessons and concludes. An Appendix lists the acronyms introduced in the paper.

2. The Electric Reliability Council of Texas

The Electric Reliability Council of Texas (ERCOT) is the corporation that administers the part of Texas' power grid that is not “synchronous” (Bergen and Vittal, 2000) with the Eastern or the Western Interconnection. Although some Texas state-wide statistics will be presented in some of the figures and tables, the parts of Texas that are served by the Eastern Interconnection will not be discussed in detail. That is, this paper will mainly discuss the ERCOT system, which covers approximately 200,000 square miles, and has its peak demand in summer, driven by air-conditioning loads.

In section 2.1, we briefly review the history and development of ERCOT and the ERCOT electricity market, presenting various statistics, and then in section 2.2 describe the principal characteristics of ERCOT market design.

2.1 History and statistics

Officially founded in 1970, ERCOT is one of ten regional reliability councils in North America operating under the reliability and safety standards set by the North American Electric Reliability Council (NERC). Figure 1 shows the regions of the ten reliability councils of NERC and shows that the ERCOT system covers most of the geographical area of Texas. As a NERC member, ERCOT's primary responsibility is to facilitate reliable power grid operations in the ERCOT system by working with the region's electric utility industry organizations. An independent Board of Directors comprised of electric utility Market Participants governs ERCOT.

[Figure 1: Regional Reliability Councils of NERC]

Because ERCOT is entirely within the state boundaries of Texas, the production and sale of electricity in ERCOT is not subject to regulation by FERC, but instead falls exclusively under the jurisdiction of the Public Utility Commission of Texas (PUCT) with laws established by the Texas legislature. The jurisdictional arrangement for ERCOT is unlike the case in the other lower 47 states where jurisdiction is split between the Federal Energy Regulatory Commission (FERC) and state public utility commissions. As discussed elsewhere in this volume, (Wolak, 2003, Section 7), the jurisdictional split between FERC and the California Public Utility Commission appears to have contributed to the electricity crisis in California. The presence of a single regulatory authority over ERCOT avoids such regulatory disputes in the ERCOT system.

In 1995, the Texas Legislature amended the Public Utility Regulatory Act (PURA) to restructure the wholesale generation market. In 1996, ERCOT was authorized by the PUCT to operate as a not-for-profit Independent System Operator (ISO) to facilitate the efficient use of the electric transmission system by all market participants. In its initial operation, the ERCOT ISO did not fulfill all the functions specified in FERC Order 888 (FERC, 1996). In particular, the ERCOT ISO was not the "control area operator" for ERCOT.

On May 21, 1999, the Texas Legislature passed Senate Bill 7 (SB7) (PUCT, 1999). Under SB7, the ERCOT ISO was given the responsibility to develop the market structure, infrastructure, and business processes to facilitate retail competition in Texas. During 1999 and 2000, the ERCOT ISO and market participants developed "Protocols," which are rules and standards that the ERCOT ISO uses to implement its market functions. The PUCT approved the market rules of the Texas wholesale electricity market (ERCOT protocols) on June 4, 2001 and the ERCOT market began to operate as a single “control area” under the ERCOT ISO on July 31, 2001.

The PUCT began implementing SB7 shortly after former Governor Bush signed the bill into law. Several rulemaking “projects” were opened by the PUCT to define the retail market in Texas, including rules relating to the code of conduct, electric reliability standards, a renewable energy credit-trading program, and wholesale market rules. As of December 2002, 41 rulemaking projects related to SB7 have been completed to implement the Act and 12 more were opened in 2003.

The ERCOT ISO serves approximately 85 percent of the state's electric load, and oversees the operation of approximately 77,000 megawatts of generation and over 37,000 miles of transmission lines. During the eight years between the introduction of wholesale competition to ERCOT in 1995 and early 2003, generation capacity in ERCOT has increased by 30%, while the peak demand increased about 20%. That is, there is currently a large amount of generation capacity relative to demand in ERCOT. About 18,000 MW of mostly independent generation capacity was added in ERCOT over this period, increasing the installed capacity from 59,000 MW to 77,000 MW, while peak demand increased from 46,668 MW to 55,703 MW. (The highest ERCOT peak demand was recorded at 57,600 MW in August 2000). Much of the resource growth has occurred in the last couple of years and was built primarily by non-utilities.

Based on the NERC report “Summer Assessment of Reliability of Bulk Electricity Supply in North America” (NERC, 2003), the summer Available Resources and Projected Peak Demand and actual peak demands (ERCOT, 2002a) in ERCOT from 1996 to 2002 are summarized in Figure 2. “Available Resources” in Figure 2 are defined to be the existing generation capacity plus new units scheduled for service by the given summer peak month and year, plus the difference between firm capacity purchases and sales, less existing capacity that is unavailable due to planned outages. Projected peak demand is the projected peak-hour demand for the given summer peak month and given year, including standby demand, less the sum of direct control load management (monthly coincident) and interruptible demands.

[Figure 2: Available Resources and Peak Demand of ERCOT (1996 - 2002)]

During the same period, transmission facilities were actively planned and built in the ERCOT region to ensure that the transmission grid could transfer the increased power supply. Over 900 miles of transmission facilities of various voltages were built between 1996 and 2003, an increase of approximately 2.5%. While this lags the rate of generation and demand growth in ERCOT, in many other regions of North America transmission growth has been smaller still.

Nevertheless, even with the large increases in generation capacity and some increase in transmission capacity, ERCOT stakeholders have been facing various problems and addressing market design issues on an *ad hoc* basis since the ERCOT protocols were implemented on July 31, 2001. This has led stakeholders to think about systematic approaches to fix problems and about the future direction for the wholesale market design. Whether ERCOT should move towards the FERC's standard market design (SMD) is becoming a key policy issue. In the next section, we present an overview of the ERCOT market design.

2.2 Overview of ERCOT market design

Four years elapsed from the opening of the wholesale market in ERCOT to competition until Senate Bill 7 (SB7) was enacted in 1999. SB7 changed the wholesale market and introduced competition to the retail sale of electricity in Texas. Each Investor-owned electric utility (IOU) was required to be unbundled into three distinct kinds of companies: a power generation company (PGC), a transmission and distribution service provider (TDSP), and a retail electric provider (REP). These entities could remain "affiliated."[2] PGCs operate as wholesale providers of generation services. REPs operate as retail providers of electricity and services and contact with the retail customers in the new market. We will first describe PGCs and REPs and then return to TDSPs. Then we will discuss retail customers, Municipal Utilities and Co-ops, and then discuss how these entities interact in the market.

In ERCOT, PGCs could and have remained affiliated with REPs, which has produced implicit "vesting" contracts between generators and retailers. Vesting contracts or other long-term contracts have been put in place in most restructured markets. In contrast, there were no such contracts between generators and retailers in California, as explained in (Wolak, 2003). The generation in California was divested to "unaffiliated" companies (Bushnell, 2003, Tables 2 and 3) and there were only limited long-term contractual links between generators and retailers. As discussed in (Wolak, 2003), the lack of long-term contracts or other vesting arrangements created incentives for generator owners in California to profit from withholding from the market to increase wholesale prices. This differs from the incentives faced by PGCs in ERCOT that have affiliated REPs and is a key difference between ERCOT and the California market.

The TDSPs remain regulated by PUCT, and are required to provide non-discriminatory access to the transmission and distribution grid. The PUCT sets the rates for transmission and distribution service. Although transmission and distribution facilities remain regulated by PUCT, the prices for the production, transmission congestion, and sale of electricity to both wholesale and retail customers are predominantly dictated by the market, except that customers with a peak demand of one megawatt (MW) or less can continue to purchase at the regulated "price-to-beat" rate until 2007, to be discussed in detail in section 3.10.

Customers have various options in the market after the introduction of retail electric competition in ERCOT. Prior to it, all retail customers were served by investor-owned electric utilities, electric cooperatives (Co-Ops), or municipally owned utilities (MOUs). Very few customers had a choice of companies to supply their power. SB7 established a framework to allow retail electric customers of investor-owned utilities to select their provider of electricity beginning January 1, 2002.

Municipally owned utilities (MOUs) and electric cooperatives (Co-Ops) were granted the authority to decide whether and when to open their service areas to retail competition under the so-called opt-in or non-opt-in provision. They are allowed to continue bundled operations regardless of their choice to open their service areas to retail competition. Evidently, the Texas legislature did not believe that it could or should impose the same requirements on MOUs and Co-Ops as it did on IOUs. As in most other state jurisdictions, restructuring in ERCOT left various entities grandfathered to operate under pre-existing arrangements.

ERCOT uses the term “Resources” to describe the entities able to meet system demand. A Resource can be a Power Generation Company (PGC), a Qualifying Facility (QF), a MOU or a Co-Op, or a Load Serving Entity (LSE) representing a load acting as a resource. A PGC is the entity registered by the PUCT that generates electricity to sell at wholesale. A PGC does not own transmission or distribution facilities and does not have a PUCT certified service area. Qualifying Facilities are a category of cogeneration or small power generating facility that meet ownership, operating, and efficiency criteria established by the FERC. Independent Power Producer (IPP) is a non-utility power generator that is not a regulated utility, government agency, or Qualifying Facility.

Load Serving Entities (LSEs) is the term used in ERCOT for entities that provide electric service to customers. They include REPs, Competitive Retailers (CRs), and Non-Opt-In Entities (NOIEs). A Competitive Retailer (CR) could be a Retail Electric Provider (REP), or a MOU or a Co-Op that offers customer choice in the restructured competitive electric power market. LSEs forecast their customer load and negotiate privately with other market participants, such as resources or power marketers, to buy energy to provide for their customer load.

The plethora of categories of Generation Resources and of LSEs reflects the co-existence of grandfathered entities with restructured IOUs and with new entities such as CRs. We will refer to Generation Resources and LSEs generically, omitting some of the detailed differences between types of Generation Resources and types of LSEs.

The matching of generation from a Generation Resource to load for an LSE constitutes a “schedule.” Market participants are required to submit their schedules of energy to the ERCOT ISO through Qualified Scheduling Entities (QSEs), which are qualified by the ERCOT ISO in accordance with the Protocol to submit Balanced Schedules and Ancillary Services bids and settle payments with the ERCOT ISO for the entities in their portfolio.

For every 15-minute interval, the ERCOT ISO compares the sum of the schedules submitted by QSEs to its own load forecasts, and determines balancing energy and ancillary services requirements. If the submitted schedules result in congestion of the transmission system then the ERCOT ISO will re-dispatch system resources to resolve the congestion. As will be discussed in section 3.3, the method of allocating costs of re-dispatching to the market participants has been changed since February 2002.

In contrast to ISOs in other restructured markets in the United States, the ERCOT ISO also serves as the registration agent for all retail transactions, including switching requests, move-in and move-out requests, and monthly electricity usage data. TDSPs are responsible for load and resource meter installation as well as submitting meter data for all loads and resource meters that are not directly polled by ERCOT.

[Figure 3: Overview of ERCOT Market Participants]

Figure 3 shows the relationship between major market participants in the ERCOT market. In addition to the entities already described above, Figure 3 also shows “power marketers” and “aggregators.” A power marketer is an entity that becomes an owner or controller of electric energy for the purpose of buying and selling electric energy at wholesale. A power marketer does not own generation, transmission, or distribution facilities in Texas and does not have a certified service area, but has been granted the authority by the FERC to sell electric energy at market-based rates or has registered with PUCT as a power marketer. Aggregators join two or more customers into a single purchasing unit to negotiate the purchase of electricity from retail electric providers. As of early 2003, there are 46 QSEs, 52 CRs, 153 aggregators, 16 REPs, 17 power marketers, 37 electric cooperatives, 16 municipally owned utilities, 8 investor-owned utilities and 5 IPPs (PUCT, 2003d; ERCOT, 2003b). In section 3 we will describe the interaction between these entities in more detail.

3. Market components and characteristics

In the following sections, we describe the components and characteristics of the ERCOT market design from the following perspectives: bilateral energy market, balancing energy market, congestion management, ancillary services market, operational issues, capacity adequacy, generator inter-connection policy, transmission planning, market power mitigation, retail competition, and load response. We will then summarize the revisions to the ERCOT market and compare it to other markets.

3.1 Bilateral Energy Market

In this section, we first introduce and describe the bilateral energy market then describe a change to the market and the implications for price discovery and liquidity.

3.1.1 Introduction

One fundamental issue of electricity market design is whether the market incorporates a central bid-based pool where resources are dispatched by the ISO based on bid prices and quantities. Electricity markets that have a day-ahead centrally dispatched energy market include the (now defunct) California PX, California MD02, the England and Wales market prior to March 2001, and the markets in the Northeastern United States. In these markets, bilateral transactions between generation and demand are essentially "financial" in nature in that the actual dispatch is decided by the pool rather than specified by the bilateral contracts. The role of bilateral contracts in these markets is to financially hedge against pool price variation.

Unlike the pool markets, the ERCOT wholesale market only has a day-ahead portfolio energy schedule process. The ERCOT portfolio schedule process is broadly similar to the California market absent the PX and to the England and Wales New Electricity Trading Arrangements (NETA) that have been in place since March 2001. Under the ERCOT scheduling process, each QSE submits schedules for their bilateral transactions with total generation and demand, specified at zonal level, and bid curves for zonal balancing up and balancing down energy. The schedules for generation and demand are required to be "balanced" in that supply equals demand for each QSE individually. The balancing energy market, which compensates for deviations between scheduled and actual generation and between scheduled and actual demand, will be discussed in section 3.2. Congestion management will be discussed in section 3.3.

Bilateral transactions represent the bulk of delivered energy in the ERCOT system and much of the bilateral transactions are between affiliates. These schedules account for about 95% to 97% of the end user electric energy requirements in ERCOT, which is close to 300 million MWh on an annual basis. In contrast to the financial bilateral transactions in pool markets, the bilateral transactions in ERCOT have a "physical" flavor in that, in principle, a bilateral transaction that is scheduled by a QSE is expected to occur.

An important philosophical question in the design of electricity markets is whether day-ahead central dispatch is necessary. The ERCOT market shows that a centrally dispatched day-ahead market may not be necessary, at least given the circumstances in ERCOT where there is a large amount of generation capacity (see section 3.5) and where most of the bilateral transactions are between affiliates. Scheduling by affiliated PGCs and REPs can be interpreted as implicit vesting contracts, which act to decrease the effect of significant market concentration in ERCOT. These circumstances contrast with the initial California market, for example, where there was central day-ahead dispatch by the PX for most generation. But, for reasons set out in (Wolak, 2003), there were few long-term contracts and, moreover, affiliations between generation and distribution companies had been removed.

3.1.2 Relaxed balanced scheduling

The stakeholders included the balanced schedule requirement in the original Protocols to be consistent with a "min-ISO" philosophy as a way of minimizing balancing energy volumes. It creates less credit and financial risk for the ERCOT ISO. However, some market participants have been concerned that the requirement for balanced schedules makes market participants unable to buy and sell energy actively. Industrial loads may want the ability to go short by contracting for less power than they need, and then purchase the remainder from a spot market or curtail their demand.

In November 2002, the ERCOT ISO implemented “relaxed balanced scheduling” on a trial basis. Until that revision, the Protocol required that each QSE submit a balanced day-ahead energy schedule based on the QSE’s load forecast for the following day. Under the relaxed balanced schedule, QSEs can schedule any amount of their demand and are not expected to schedule demand equal to their forecast. The expectation is that a larger fraction of energy would be transacted in the balancing market, increasing the liquidity in this market.

After several bankruptcies due to exposure to high balancing market prices, relaxed balanced scheduling was modified in April 2003 to limit the allowable deviation between the schedules and forecast.

3.1.3 Price discovery and liquidity

Two main concerns about the ERCOT bilateral market are price discovery and liquidity. Since buyers and sellers generally negotiate in private, and do not have to disclose the price and terms of contracts to others, it may be difficult for buyers and sellers to know the prevailing market price. The lack of price transparency makes it difficult to value the offers for services appropriately.

Liquidity is related to the volume of trades in a market. Lack of liquidity makes it difficult for a party to sell the excess or buy the deficiency in the market. The volume of wholesale trading between non-affiliates has been a small fraction of the total energy in the ERCOT market, and some stakeholders have expressed concerns about the lack of liquidity (PUCT, 2002f). A day-ahead energy market with a third party intermediary is supported by some market participants in part to improve liquidity (PUCT, 2002g). According to the 2003 reports to legislature by the PUCT, several parties have expressed concerns that REPs and their affiliated power generation companies (PGC) in ERCOT have largely contracted with each other in bilateral contracts, thereby limiting the ability of new generation plants to compete to serve retail customers. This problem should decrease over time as customers switch to alternate suppliers, placing increased pressures on the affiliated REPs to procure the least expensive power available. (See section 3.10.) On the other hand, a weakened connection between PGCs and REPs will increase incentives for PGCs to withhold to increase wholesale prices. (See section 3.9.)

The PUCT is currently exploring these issues in several pending rulemaking proceedings and projects (PUCT, 2002h-j). The elements of the FERC's SMD, which could add transparency and liquidity to the ERCOT markets, are also under consideration. Some stakeholders believe that the ultimate solution to the problem is to implement a spot market similar to SMD.

3.2 Balancing Energy Market

The ERCOT market design reflects the philosophy of minimizing the involvement of the ISO (min-ISO) in the electricity market, where the ISO just operates a residual market or a "net pool" (Hogan, 1995). The ERCOT ISO is only involved in the transaction of the imbalances of the bilateral generation and load schedules and in clearing congestion and other actions to keep system reliability. About 2% to 5% of the total energy is transacted through the balancing energy market operated by the ERCOT ISO.

According to the ERCOT market guide (ERCOT, 2001), the market operations process contains three major periods: Day-Ahead Ancillary Services market, Adjustment Period, and Operating Period. The day-Ahead Ancillary Services Market occurs from 6:00AM to 6:00PM on the day prior to the operating day. QSEs submit portfolio schedules and ancillary services bids. As will be discussed in section 3.4, the ERCOT ISO assesses the needs for and procures ancillary services for the following operation day.

The adjustment Period happens between the close of Day-Ahead Ancillary Services Market and one hour prior to the Operating Hour (the current clock hour). QSEs may adjust their energy and ancillary service schedules and update their resource plans during this period. QSEs may also submit, remove or adjust their Balancing Energy and Replacement Reserve bids during the adjustment period. Based on the analysis of schedule changes, resource plans, load forecasts, and other system conditions, the ERCOT ISO may procure additional ancillary services during the adjustment period by announcing the need to procure additional services and opening subsequent markets. By the end of the adjustment period, ERCOT receives final bids for balancing up and down energy services.

The operating period includes the Operating Hour and the hour prior to the Operating Hour. Based on the submitted portfolio schedules, forecasted load and bid prices, the ERCOT ISO clears the balancing market to keep system balance and so that flows on the inter-zonal Commercially Significant Constraints (CSCs) are within their transmission capacities. The ERCOT ISO also conducts the security-constrained reliability analysis by distributing the generation portfolio dispatch and forecasting demand at the nodal level. If necessary, the ERCOT ISO requests unit-specific energy bids, as well as Out-of-Merit Energy, Reliability-Must-Run units, or Non-Spinning Reserve energy. Ten minutes prior to the Settlement Interval (which is itself of duration 15 minutes), the ERCOT ISO clears the balancing energy market, and instructs those QSEs whose bids were selected to provide balancing energy for the Settlement Interval.

Settlements of the balancing energy are based on the zonal aggregate load imbalance and resource imbalance for each QSE. The load imbalance is the difference between the scheduled load and actual load from each QSE, while the resource imbalance is the difference between the scheduled generation and actual generation for each QSE. The actual load and generation amounts are derived from the load and resource meter readings.

3.3 Congestion Management

In this section, we introduce the process of transmission congestion management in ERCOT. The general process of re-dispatch to relieve transmission congestion is discussed in section 3.3.1. The ERCOT ISO uses a flow based zonal congestion management scheme. The ERCOT transmission grid, including generation resources and loads, is divided into several congestion zones that are determined on an annual basis. Each congestion zone is defined such that every generation resource or load within the congestion zone boundaries has a similar effect (characterized by its “shift factor”) on the transmission facilities that limit transfer between congestion zones. These transmission facilities are called Commercially Significant Constraints (CSCs). The CSCs will be discussed in section 3.3.2.

The ERCOT ISO categorizes congestion management as either zonal congestion or local congestion. The former encompasses managing congestion on CSCs or predefined Closely Related Elements (CRE). QSEs specify portfolio bid prices for zonal balancing energy to the ERCOT ISO and these bids are used to relieve zonal congestion. Generators are exposed to locational prices that reflect the average effect of location in zones on CSCs.

In addition to congestion on CSCs and CREs, congestion can occur on transmission paths within a zone, which is called “local congestion.” and will be discussed in section 3.3.4. Local congestion management relies on a more detailed operational model to determine how each particular resource or load influences the transmission system. The cost of the re-dispatch used to solve local congestion is uplifted to each QSE based on its Load Ratio Share (LRS). The same method of uplift was used for zonal congestion before Feb. 15, 2002. After this date, “direct assignment” of zonal congestion rent was implemented, which will be discussed in section 3.3.3.

3.3.1 Re-dispatch to relieve congestion

The ERCOT ISO analyzes schedules submitted by the QSEs to determine whether the resulting flows are within the system transmission capability. When the power scheduled to be transferred on a transmission facility element or set of elements would exceed the transfer capability of the elements, the ISO has to re-dispatch generators to ensure the reliability of the system. We will illustrate this re-dispatch process with a simple two zone system and clarify some definitions related to congestion before discussing congestion management in ERCOT.

[Figure 4: Two zone system]

[Figure 5: Congestion Costs and Rents]

Figure 4 shows a two zone system with zones A and B. The generation resources in zone A are more expensive than in zone B. Zone A is a net load zone, while zone B is a net generation zone. The marginal cost of net supply at A and the marginal avoided cost at B are shown in Figure 5. If there were no transmission capacity limit, then QSEs can schedule the cheap resources at zone B to supply the demand at zone A. As shown in Figure 5, neglecting distortions due to market power, the market price at node A and node B would both be P_C, and the import to zone A and the export from zone B would both be equal K1.

However, suppose that the transmission capacity between zone A and zone B were limited to K, as shown in Figure 5. If K is less than K1, then the ISO has to re-dispatch the system. The generation output at B is decreased by (K1-K), and the output of generators in zone

A is increased by (K1-K) to meet the demand in zone A. In the absence of market power, the market clearing prices at A and B are P_A and P_B, respectively. The difference between these prices is the "shadow price" of the transmission capacity between node A and node B. The "re-dispatch cost" (Stoft, 2002; Oren, 2002b, 2003) under a marginal clearing mechanism (the rectangular area DIEF) is $(P_A - P_B) * (K1\text{-}K)$, which is the net payment by the ISO to increase the output of expensive generators in A and decrease the output of cheap generators in B. The rectangular area DIGH and the triangular area DIC in Figure 5 are called "congestion rent" and "congestion cost," respectively, (Oren, 2002a, 2002b, 2003; Joskow, 2003). The "congestion cost" is the loss of social welfare due to the constraint.

In ERCOT, the term "congestion cost" is (confusingly) used to refer to either the congestion re-dispatch cost or the congestion rent, depending on the context. We will avoid this usage and instead use terms as defined in the previous paragraph.

3.3.2 Commercially significant constraints

The effect of a generator or load on a transmission facility is characterized by its "shift factor." In ERCOT, busses with similar shift factors are combined into a zone. Zonal generation-weighted average shift factors, determined by the ERCOT ISO, are used as an approximation to the actual shift factors to manage congestion on Commercially Significant Constraints (CSCs).

Assuming a single shift factor for all resources and load in each zone allows the resources and load in a zone to be considered without regard to their specific location. This enables resource scheduling and bidding as a portfolio rather than as specific units. The portfolio energy schedules submitted by each QSE specify its total generation and demand in each zone. Any imbalance between loads and generation resources in a congestion zone is assumed to have the same impact on a given CSC.

ERCOT re-assesses CSCs annually, based on the changes of the system topology. New congestion zones may be identified based on the re-assessed CSCs. In 2001, there were three congestion zones in ERCOT: North Zone, South Zone and West Zone, and two CSCs: transmission from Graham to Parker and from Limestone to Watermill. There have been four congestion zones for 2002 and 2003: North Zone, South Zone, West Zone and Houston Zone. The transmission from Sandow to Temple, Graham to Parker, STP to DOW, and Parker to Graham were the CSCs for 2002. There are only three CSCs in 2003, involving transmission from STP to Dow (South to Houston), from Graham to Parker (West to North) and from Sandow to Temple (South to North). The CSCs and congestion zones of ERCOT in 2003 are shown in Figure 6.

[Figure 6: CSCs and congestion zones of ERCOT in 2003]

The zonal model feature of ERCOT is related to the geographical arrangements of each utility's generation and load before ERCOT began to operate as a single area. There were 10 control areas within ERCOT prior to July 2001. The companies scheduled and operated their generation and load within each area as an entity. Under portfolio scheduling and zonal congestion management, market participants can maintain their pre-existing portfolio management approaches, including self-commitment of generation resources.

When only transmission congestion on CSCs needs to be managed within the ERCOT region, only portfolio-balancing instructions are issued on a zonal basis. QSEs only need to meet their portfolio obligations zone by zone and no unit-specific deployment instructions are issued. The Market Clearing Price of Energy (MCPE) is determined for each zone based on the zonal portfolio offer curves for the balancing energy, forecasted load, and inter-zonal transmission constraints. If there is intra zonal congestion, however, ERCOT uses unit-specific bids to relieve local constraints and to issue unit-specific instructions to clear local congestion. This will be discussed in section 3.3.5.

The zonal aggregation and use of a single weighted average shift factor means that the economic signals for congestion are approximate. Empirical data shows that the assumptions underlying the use of the zonal average shift factors to approximate the actual shift factors are violated in ERCOT. The implication is that, under some circumstances, the average shift factors provide incentives that deviate significantly from the efficient level (Baldick, 2003). Moreover, interaction between the zonal and local congestion management process (to be discussed in section 3.3.5) poses operational difficulties for the ERCOT ISO.

The portfolio market structure and zonal congestion management model have provided operational flexibility to the ERCOT market participants, but also brought difficulties to the operation of ERCOT ISO. If the ERCOT transmission system were less robust or the supply more limited then the inefficiencies due to zonal aggregation would be more problematic.

3.3.3 "Direct Assignment" of Zonal Congestion Rent

When ERCOT began operation as a single "control area" on July 31, 2001, interzonal congestion re-dispatch costs were uplifted among market participants on a "load ratio share" basis. This presented an opportunity for profiting by over-scheduling and then being paid to relieve congestion. This is similar to the "Inc and Dec" game in the California market. Serious over-scheduling was observed in August 2001. The re-dispatch costs and the costs related to load imbalance, resource imbalance, and uninstructed deviation are aggregated as Balancing Energy Neutrality Adjustment (BENA) charges. BENA charges for August 2001 alone were approximately $75.9 million. Six QSEs received more than $2 million each in load imbalance revenues for that month. A settlement was reached with them agreeing to refunds of gains from the ERCOT market.

The potential for this problem was anticipated (Oren, 2001) and the PUCT required ERCOT to switch to a “direct assignment” methodology (that is, charging zonal congestion rents) by January 1, 2003 or six months after inter-zonal re-dispatch costs rose above $20 million on a rolling twelve-month period, whichever came first. It also required ERCOT to implement a system of transmission congestion rights (TCRs), which would allow market participants to hedge their inter-zonal congestion charges.

The $20 million threshold for inter-zonal re-dispatch costs was reached on August 15, 2001, just 15 days after beginning of the operation as a single control area. “Direct assignment” and the TCR system were implemented on February 15, 2002. Under it, the charge or payment to a QSE is based on the product of its scheduled flow and shadow prices on the congested CSCs. That is, a QSE is exposed to the variation of the shadow price for the CSC.

Transmission Congestion Rights (TCRs) and Pre-assigned Congestion Rights (PCRs) were implemented as financial hedges against the zonal congestion rent. The TCR and PCR holder receives an amount equal to the congestion rent for an equivalent quantity of scheduled flow. TCRs are awarded in yearly and monthly simultaneous combinatorial auctions based on the auction clearing prices. As discussed below, PCRs are allocated to MOUs and Co-Ops rather than awarded by the TCR auction process and are priced differently to TCRs. For all other purposes, PCRs are functionally and financially equivalent to TCRs.

MOUs and Co-Ops that made a long-term (greater than five years) contractual commitment for annual capacity or energy from a specific remote generation resource prior to September 1, 1999, are eligible for PCRs between the zone of their resource and the zone of their demand. PCRs are available on an annual basis until the date upon which an MOU or Co-Op implements retail customer choice, or alternatively, until such other date as may be specified by Order of the PUCT. The cost of PCRs equals fifteen percent of the applicable annual TCR auction clearing price for each CSC for which a PCR is allocated. PCRs may be traded in the secondary market. Holders of PCRs are not precluded from participating in the market to purchase additional TCRs.

The ERCOT ISO initially conducted a simple, single round TCR auction for each CSC. The auction awarded the TCRs from the highest prices to the lowest prices until 100% of the TCR capability is awarded. The lowest awarded price becomes the market clearing price for the TCRs for the CSC. However, a transaction from one zone to another requires capacity on several CSCs simultaneously. Consequently, the value of a TCR on one CSC depends on the amount of TCR awarded on other CSCs (Oren, 2001). That is, TCRs for the various CSCs are closely inter-related products. Having separate markets for them poses difficulties for achieving efficiency.

To respond to this issue, the Congestion Management Working Group of the Wholesale Market Subcommittee drafted PRR 329 in May 2002 to implement the PUCT order to convert the simple auction to a combinatorial auction of TCRs. This PRR was approved on May 9, 2002, and it became effective on January 1, 2003. By this revision, the ERCOT ISO conduct a single-round, simultaneous combinatorial auction for selling the TCRs available for each annual or monthly auction for all CSCs. In this auction, bidders can reflect their needs for TCRs on multiple CSCs simultaneously. The clearing-price for each TCR equals to the corresponding shadow price of the marginal TCR awarded on that CSC.

Under some circumstances, PCRs and TCRs have the potential to enhance electricity seller or buyer market power (Oren, 1997; Joskow and Tirole, 2000). As an *ad hoc* approach to mitigating market power, no entity combined with its affiliates may, directly or indirectly, own, control, or receive the revenue from more than 25% of the total available TCRs at a CSC interface for any single direction and a given hour. Market power will be discussed in more detail in section 3.9.

Figure 7 shows the monthly zonal re-dispatch costs (until February 14, 2002) and congestion rent (after February 15, 2002) in ERCOT. Until February 14, 2002, zonal re-dispatch cost was uplifted to all QSEs in the system based on their load ratio share. From February 15, 2002, direct assignment of zonal congestion rent was implemented in ERCOT, under which the congestion charge or payment for each QSE is based on the shadow prices and power flow it scheduled on the congested CSCs. Zonal congestion rent after February 15, 2002 was significantly less than the re-dispatch cost prior to February 15, 2002. This strongly suggests that significant over-scheduling was taking place prior to February 15, 2002. Over-scheduling across the CSCs has stopped and should not re-occur because the change to direct assignment of zonal congestion rent removed the incentives for QSEs to over-schedule load across the CSCs. The same problem still remains for local congestion, as will be discussed in section 3.3.5.

[Figure 7: Zonal Re-dispatch Cost (Aug. 1, 2001 – Feb 14, 2002) and Congestion Rent (Feb. 15, 2002 – Dec. 30, 2002)]

3.3.4 Difficulties in adequately hedging congestion rent

One of the goals of a zonal congestion model is to simplify the commercial model to facilitate trading. However, the need to change the model on an annual basis has a deleterious effect on long-term commercial activities. The annual revision of congestion zones creates uncertainty and results in a lack of liquidity in the forward market for zonal products. Since the boundary shifts are difficult to predict, trading of long-term zonal products is risky for a power generation company if it has assets near the zone boundaries or if zones are sub-divided.

A similar problem is the inability to make long-term purchases of TCRs. It is difficult for REPs and QSEs to hedge congestion rent adequately in long-term. Ownership limitations on TCRs (opt-ins limited to 25% of total available TCRs per CSC, non opt-in limited to same 25% of TCRs, plus their PCRs) has also been cited by market participants as an obstacle to fully hedging risk, although the limit on TCR ownership is aimed at mitigating exercise of generation market power.

To address this problem, the creation of trading hubs has been proposed as a solution to provide certainty regarding delivery expectations. The ERCOT managed hubs are expected to enhance the market stability by allowing participants to arrange transactions, despite annual rezoning. Long-term hedging of congestion is a problem in other markets as well as in ERCOT; however, the annual rezoning in ERCOT exacerbates the problem.

3.3.5 Local Congestion

A similar situation continues to exist for local congestion as existed for zonal congestion prior to February 15, 2002. However, ERCOT relies on a more detailed operational model to determine how each particular resource or load affects the transmission system and this model does not use portfolio bids. Each resource is required to submit resource specific premiums (positive or negative) and the resource-specific dispatch ranges. The resource specific premiums and unit specific shift factor are used to relieve local congestion through a set of balanced adjustments to local resources in each zone. Resources in other zones may be chosen when there is no solution within local resources.

The ERCOT protocols define a “market solution” for local congestion as when at least three unaffiliated resources, with capacity available, submit bids to the ERCOT ISO that can solve the local congestion and no one bidder is essential to solving the congestion. If there is no market solution then bid prices are mitigated based on verifiable operating costs.

There has been no “market solution” for local congestion in ERCOT in most cases. That is, local market power (to be discussed in section 3.9) is deemed to exist most of the time when local transmission constraints are binding. Instead of relying on a market process to determine prices, ERCOT obtains commitments to provide capacity and energy at a pre-specified cost level. These are called Out of Merit Order Energy (OOME) and Out of Merit Order Capacity (OOMC). OOME services are provided by resources selected by ERCOT ISO outside the bidding process in order to resolve local congestion when no market solution exists. OOMC provides generation capacity needed such that balancing energy is available to solve local congestion or other reliability needs when a market solution does not exist. OOMC can be provided from any resource or load acting as a resource that is listed as available in the resource plan.

Sometimes a Reliability Must Run (RMR) unit may be needed to provide generation capacity or energy resources when there is no market solution. A RMR unit is a generation resource unit operated under the terms of an annual agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability, or management of localized transmission constraints under first contingency criteria where Market Solutions do not exist.

The local congestion cost is uplifted to each QSE based on the load ratio share of the QSE. Figure 8 shows the local re-dispatch costs in ERCOT from August 2001 to December 2002.

[Figure 8: Local Re-dispatch Cost of ERCOT]

In Docket 23220 of 2001, the PUCT ordered the ERCOT ISO to implement direct assignment of local congestion costs if the re-dispatch costs for resolving local congestion rose above $20 million in a rolling twelve-month period. The direct assignment of local congestion cost tries to eliminate opportunities for market participants to profit from scheduling that result in congestion on local transmission lines and to send appropriate signals to locate new generation facilities in places that have sufficient transmission capacity to deliver the power to electric consumers. The $20 million threshold for local re-dispatch costs was met on March 5, 2002, after seven months of operation as a single control area.

Several proposals have been suggested for solving the local congestion problem, including implementing nodal locational marginal pricing (LMP). ERCOT is currently implementing a Texas Nodal Market design process.

3.3.6 Summary

The clear lesson from both California and ERCOT is that uplifting re-dispatch cost is a serious flaw in market design. The problems with uplifting re-dispatch cost were recognized at the time the ERCOT Protocols were approved and the triggers to implement the change were set to deal with this issue (Oren, 2001). In the case of zonal re-dispatch costs, the change from uplifting to charging congestion rent was relatively straightforward and has been implemented. In the case of local re-dispatch, however, the issue cannot be resolved without finer-scale disaggregation of the system including unit-specific scheduling and bidding, which will render the zonal portfolio scheduling process untenable.

The TCRs for the three CSCs are closely inter-related products. Auctioning them separately, as in the original implementation, leads to inefficiencies. Such closely inter-related products should be auctioned simultaneously.

The approach to defining "market solutions" accepts the transmission and generation system as given and then mitigates market power by regulating the prices. This approach provides no long-term solution to the problem because it does not encourage new entry to contest the local market power. Moreover, the lack of transparency due to the uplifting of congestion costs tends to entrench local monopoly power.

3.4 Ancillary Services Market

Ancillary services (AS) are the services necessary to maintain electric system reliability and security. In ERCOT, each market participant is assigned an obligation to provide ancillary services based on its historical load. Market participants may provide the ancillary services themselves or rely on the ERCOT to acquire the ancillary services through a centralized auction. From August 2001 to December 2002, market participants self-procured between 80% and 90% of their AS obligations.

ERCOT operates a day-ahead AS market for: Regulation Down Services (RgDn), Regulation Up Services (RgUp), Responsive Reserves Services (RRS), Non-Spinning Reserve Services (NSRS), and Replacement Reserve Services (RPRS) as needed. These ancillary services are procured day-ahead for each hour of the following day.

One concern about AS markets is price reversal (Oren, 2000), where the Market Clearing Prices of Capacity (MCPC) for the higher quality ancillary services are lower than the prices for the lower quality ancillary services. This occurs because, in the initial ERCOT implementation, the markets for Regulation Services, RRS and NSRS are cleared in sequence. Sometimes lower quality ancillary services were offered from generating units that are capable of producing higher quality ancillary services when lower quality services were anticipated to receive higher prices. This may result in a shortage of higher quality services such as regulation up and down services. From August 2001 to September 2002, the monthly average percentage of price reversal hours in ERCOT was about 35%.

Since ancillary services are inter-related products and since generators can provide several types of ancillary services, having separate markets for ancillary services poses difficulties for achieving efficiency. This is analogous to the case for auctions of TCRs for CSCs. In order to procure ancillary services efficiently and prevent price reversal, Protocol Revision Request (PRR) 342 for simultaneous selection of AS services was submitted in May 2002. It was approved by the ERCOT Board on January 22, 2003 and will be in place after the ERCOT systems are changed accordingly.

3.5 Operational Issues

Market participants and the ERCOT ISO are currently discussing how to improve the operational efficiency and the system reliability. QSEs that represent resources are required to submit to the ERCOT ISO a resource plan about the availability of their resources and the planned operating level of each resource for each hour of a day. The capacity indicated in the resource plan must be sufficient to support the portfolio schedules that the QSE has submitted.

In some instances, the ERCOT ISO has encountered problems with inaccurate resource plans, which have the potential to cause problems in maintaining system reliability. Schedule Control Error (SCE) (the difference between the QSE's actual resource output and its base power schedule plus instructed ancillary services) resulting from inaccurate resource plans may lead the ERCOT ISO to acquire additional ancillary services. In addition, since resource plans are used by the ERCOT ISO to identify available units that can solve a congestion problem, an inaccurate plan may make it difficult for ERCOT to manage transmission congestion.

A special team of stakeholders has been formed to develop recommendations for the resolution of this issue to improve the accuracy of resource plans. In June 2002, PRR 287 imposed stricter requirements for generators to adhere to their production schedules in order to improve reliability.

Although portfolio scheduling and the adjustment period bring flexibility to market participants, they cause other problems for system operation. For example, in order to issue a portfolio instruction, shift factors of each bus within a zone on CSCs are assumed to be the same and effects on local congestion in other zone are ignored. As discussed in section 3.3.2, this is in conflict with the physical laws of electricity (Baldick, 2003) and means that incentives are distorted compared to efficient signals. It also potentially causes some QSEs to commit inefficient generation on line, because there is no central unit commitment and dispatch in the ERCOT market. Several market participants have expressed concerns that older and inefficient generation appears to be running at times when newer, more efficient generation is idle, raising a concern about the efficiency of the current market design.

Moreover, since the ERCOT ISO does not issue a unit commitment and does not dispatch all resources of the commercial model, it has to make assumptions based on limited information available ahead of real-time to procure balancing energy services and manage congestion. These assumptions may not consistent with real time operations because ERCOT lacks details about the

QSEs' internal dispatch rationales. Accurate nodal information is necessary to efficiently operate the electric system and maintain system reliability.

It is hard to evaluate the trade off between the market participant flexibility and the technical inefficiency that the portfolio structure brings to the market. Moreover, the deviation of the ERCOT market process from other market structures, such as SMD, means that analysis of and solutions to operational inefficiency problems cannot easily benefit from experience in other North American markets.

3.6 Capacity Adequacy

In order to meet reliability criteria, there must be adequate installed capacity. The "reserve margin" is used to characterize capacity adequacy and is defined as the difference between total electricity generation capacity and peak demand, divided by the peak demand.

The ERCOT ISO periodically determines the minimum reserve margin required to ensure the adequacy of installed generation capability. ERCOT utilities have traditionally been required to maintain a reserve margin of 15%. In mid-2002, the ERCOT ISO Board approved a 12.5% reserve margin requirement; however, there is no formal mechanism in place currently to enforce the reserve margin. The PUCT is in the process of developing a reserve margin mechanism.

The strong gas delivery infrastructure and the regulatory environment, including the introduction of wholesale competition in Texas and the generation inter-connection policy (see section 3.7) have attracted the investment of new efficient generation facilities. A significant amount of new generating capacity has been added in Texas since wholesale competition was introduced in 1995. About 22,000 MW of new capacity has been added between 1995 and early 2003, with another 7,500 MW under construction. Of this amount, more than 12,500 MW was added in 2001 and the first three quarters of 2002. As of early 2003, ERCOT generation capacity is approximately 77,000 MW. Another 7,000 MW is expected to be added by the end of 2003.

According to the Goal for Natural Gas of PURA, at least 50% of new generating capacity (in MWs) installed in Texas, excluding renewables, should use natural gas as its primary fuel. Since January 1, 2000, 100% of the new non-renewable generating capacity added in Texas has been gas-fired. The total gas-fired capacity added in Texas since January 1, 2000 has been 16,800 MW. Figure 9 shows the installed generation mix in Texas in 2002.

[Figure 9: Generation mix in Texas]

Because of the nationwide economic turndown and a mild summer, the actual peak for ERCOT in summer 2002 was below the projection. (See Figure 2). Consequently, the effective reserve margin (based on actual generation capacity minus peak load, divided by peak load) of approximately 34% was higher than predicted. ERCOT predicts a 21.0% reserve margin in 2003, 21.6% in 2004, 18.3% in 2005, and 16.1% in 2006, and 13.6% in 2007. Figure 10 shows the projected available resources and peak demands from 2003 to 2007.

[Figure 10: Summer Peak Demand, Capacity and Resource]

Several issues have enabled new generation construction in ERCOT (and the “dash for gas” in England and Wales), including the availability of natural gas, the electric transmission inter-connection policy (to be discussed in section 3.7), and the environmental permitting process. The large amount of new generation has put pressure on older plants to be retired or mothballed. The nationwide economic slowdown and the potential availability of mothballed units and imports suggest that the estimated margins above for the coming years may be conservative. That is, the actual margins including use of all mothballed units and imports could be higher by several thousand MW.

As a countervailing effect, the pace of development and construction of new generation has reduced in response to slower demand growth and the nationwide economic downturn. More than 9,700 MW of announced new generation capacity planned for Texas has been delayed and more than 4,400 MW has been cancelled. Additionally, AEP and CenterPoint Energy announced in fall 2002 that they plan to mothball, collectively, a further 7,000 MW of older, less-efficient generating capacity, which may reduce the projected ERCOT reserve margins. That is, the actual margin may be lower by many thousands of MW if mothballing and cancellation occurs. Consequently, there is considerable uncertainty in the future reserve margins.

In ERCOT, the absence of an ICAP market or other mechanism to ensure adequacy implies that the large reserve margins reflect expectations by investors in new generators that their capacity would be profitable based on energy and ancillary services prices alone. However, the extremely high reserve margins mean that considerable capacity is not being used and that, in the absence of transmission constraints, competitive pressures will presumably drive down wholesale energy prices in ERCOT (Cunningham, Baldick, and Baughman, 2003). While this will yield low prices in the short term, the large expenditure on capital beyond the needed reserve margins represents a significant cost to society. This may be indicative of a boom and bust cycle in generation expansion.

3.7 Generator Inter-connection Policy

ERCOT has been proactive in encouraging new generation through its inter-connection policy. In some other jurisdictions, developers of new generation projects pay upfront for upgrades to the transmission network necessary to deliver their energy to demand. New generation facilities in ERCOT pay upfront only for the “shallow” costs of inter-connecting with the transmission network and not for “deep” inter-connection costs of upgrading the network to accommodate moving power from the resource to demand centers.

The choice between charging shallow versus deep interconnection costs has important implications for efficient growth of generation. In the England and Wales market, a similar choice of shallow interconnection costs led to considerable gas-fired generation being built near the North Sea but far from demand centers, posing considerable problems for transmission network planning. Analogous issues are arising in ERCOT. Section 3.8 discusses the transmission planning process in ERCOT.

3.8 Transmission Planning

The ERCOT ISO is responsible for transmission planning on a regional basis in ERCOT. Planning criteria for ERCOT were set by combining the NERC planning standards and the criteria that the ERCOT market participants proposed. The ERCOT Planning Assessment and Review Working Group (PARWG) review the planning criteria every three years to ensure that they meet the requirements outlined in the NERC planning standards. PARWG also periodically reviews the planning criteria, procedures, and practices of individual TDSPs to ensure the consistency with NERC and the ERCOT criteria.

PURA § 39.155, as amended by SB7 in 1999, requires the ERCOT ISO to submit an annual report to identify existing and potential transmission constraints and recommend actions for meeting system needs. The ERCOT ISO currently leads three regional planning groups (North, South, and West) to determine if additional actions are needed to resolve transmission constraints.

New transmission lines are constructed by the TDSPs. A utility is required to obtain a certificate of convenience and necessity (CCN) from the PUCT before constructing transmission facilities in Texas. In order to encourage the construction of new transmission facilities, transmission access rules were revised in 2001 (PUCT, 2001a). The Transmission Cost Recovery Factor (TCRF) was established to permit a utility to receive expedited cost recovery of additional transmission investments. TCRF only recovers the capital costs associated with new investments in transmission facilities and reflects the costs in the non-bypassable rates charged to REPs. All REPs must pay TDSPs for delivering electricity to the REP's customers. The charges are called "non-bypassable fees" because every customer pays these charges, regardless of which REP the customer chooses.

Transmission facilities have been actively planned and built in the ERCOT region. Between 1996, when ERCOT ISO began conducting regional transmission planning, and early 2003, over 900 miles of transmission facilities of various voltages in ERCOT (including over 400 miles of 345 kV transmission facilities) have been built. Major finished transmission projects include the Limestone-Watermill project, which was intended to increase transmission capacity from South Texas to North Texas, and numerous projects in the Houston and Corpus Christi areas, which were also intended to reduce likelihood of "voltage collapse" and provide "dynamic voltage control" (Bergen and Vittal, 2002).

Although a relatively large amount of new transmission facilities has been installed in ERCOT, transmission constraints in ERCOT limit the deliverability of some generation resources, especially wind power from the McCamey area in West Texas, where there is now considerably more generation capacity than there is transmission capability to export the power. The proactive inter-connection policy has encouraged new generation, but this has put strong pressure on the transmission system. This issue was introduced in section 3.7.

An important issue in most restructured electricity markets is the disconnection between generation construction and transmission planning. Although ERCOT has been active in building and upgrading transmission, ERCOT is not immune from this problem, which has been exacerbated by the generation inter-connection policy and lack of local congestion price signals.

For example, as mentioned above, in the McCamey area of west Texas, transmission resources are inadequate to transmit the wind energy generated there to load centers. New wind power capacity of 758 MW has been installed in the area as of the end of 2002 and another 300 MW is expected to be in service by the end of 2003. However, the local transmission network currently can only export 400 MW and, under the ERCOT inter-connection policy, the wind turbines were permitted to inter-connect with ERCOT despite the lack of transmission capability. This has resulted in routine wind power curtailments, higher local re-dispatch costs and damages to transmission equipment due to overloading. The transmission utilities serving the McCamey area are seeking approval for upgrades that would increase export capacity to 2,000 MW, but these improvements would not be finished until 2007.

The uncertainty regarding the expiration of the federal production tax credit (PTC) for renewable energy caused the rush to install wind capacity despite the lack of transmission capacity. The PTC, currently $18 per MWh, will expire at the end of 2003 unless it is extended by the Congress and the President. PURA § 39.904, *Goal for Renewable Energy* required that 400 MW of new renewable capacity be installed in Texas by 2003. As of October 1, 2002, approximately 1,000 MW of new renewable capacity had been installed and the majority of installed renewable capacity is wind generation. Retail market participants have an incentive to contract for more wind power to gain more PTC and share of the limited transport capacity. However, entities throughout ERCOT are paying for excessive amounts of OOME due to the concentration of wind power in areas where there is not adequate transmission available. Similar problems could arise elsewhere, depending on where future generation is sited.

In order to find ways to address this problem, Project 25819, *PUC Proceeding to Address Transmission Constraints Affecting West Texas Wind Power Generators,* has been opened. The methods for allocating transmission access and PTC in the highly constrained area would be examined.

The lack of nodal wholesale price signals has contributed to the generation siting problem. If there were proper locational signals, new generators would have had an incentive to avoid the McCamey area and locate in places where transmission was sufficient. Locational pricing issues are addressed in Project 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*.

The ERCOT inter-connection policy has enabled IPPs to inter-connect in advance of adequate transmission capability. When coupled with tax credits and the state legislative requirement for installation of renewables, the result has been generation development outpacing transmission construction. The lack of coordination between generation siting decisions and transmission analysis and planning poses serious problems for ERCOT. Transmission planning remains an extremely difficult issue in restructured electricity markets, including ERCOT.

3.9 Market Power

Market power is the ability of a firm to set price profitably above competitive levels reflecting marginal costs. Market power becomes problematic when a firm has the ability to significantly influence market prices and cause them to vary from competitive levels for an extended time. Participants may have market power through controlling a large share of the market, by being “pivotal,” or through exercising control under certain market conditions. A bid cap is a common approach in almost all markets to mitigate market power. The PUCT has established Bid Caps of $1000/MWh for energy and $1000/MW per hour for capacity.

The notion of a "market solution," as defined in section 3.3.5 is used as an indicator of when local market power may be exercised. As mentioned in section 3.3.5, if there is no market solution then market power is deemed to exist and prices are mitigated.

The PUCT's Market Oversight Division (MOD) has developed another market power mitigation approach called the Competitive Solution Method (CSM) (Oren, 2002c; PUCT, 2002a). The implementation of CSM for the balancing energy service market depends upon the congestion management method adopted by the Commission in Project No. 26376 (PUCT, 2003f).

In PUCT project 26736, other market power mitigation methods have also been discussed, such as Automatic Mitigation Procedure (AMP) and Zonal-ERCOT-Nodal (ZEN) (Siddiqi, 2003). AMP is an automated ex ante measure based on behavioral mitigation. Its ex ante nature implies that market participants avoid the regulatory risk and disruptions to settlements and financial accounting caused by refunds. It was first implemented by the NYISO.The ZEN approach tries to distinguish between changes in bidding pattern due to true scarcity in the market as opposed to locational market power. This approach is aimed at providing price signals to the market the reflect scarcity when it occurs.

Even absent local congestion, the ERCOT market is concentrated in the sense that there are a small number of IOUs owning the bulk of generation. If this market power were not mitigated then wholesale prices could be expected to be well above competitive levels (Cunningham, Baldick, and Baughman, 2003). However, the retail load obligations of the IOUs are implicit vesting contracts that considerably blunt the incentives for exercising market power.

As explained in Wolak (2003), this contrasts with the absence of any vesting arrangements or long-term contracts in the ostensibly less concentrated California market. As will be discussed in section 3.10, the extent of these retail load obligations will change as the market share of competitive retailers changes.

When there is local congestion, local market power is mitigated in ERCOT by *ad hoc* procedures that are aimed at keeping prices relatively low while maintaining transmission flows within limits. As described in Joskow (2003), however, the prices may be too low when there is local scarcity. In particular, the prices may not be high enough to attract efficient new entry to provide long-term solutions to the local market power problems. It is difficult for new entrants to contest such local markets, so that the local monopoly positions are essentially entrenched.

3.10 Retail Competition

Senate Bill 7 (SB7) required the creation of competitive retail electricity market that gave customers the ability to choose their retail electric providers starting on January 1, 2002. On June 1, 2001, a Texas Electric Choice Pilot Project (or Pilot Project) was started in advance of full retail competition in order to inform customers how to participate in the new competitive electric market and to make the system ready for the full implementation of retail competition. In the Pilot Project, 5% of electric load within each investor-owned electric utility's service was permitted to buy power from competitive retail electric providers. At the end of the pilot project, over 115,000 customers had enrolled in the pilot project. Approximately 90% of these customers were residential, 9% were small non-residential (peak demand less than one megawatt), and 1% were large non-residential (peak demand over one megawatt).

In contrast to fixed-price regimes established in electricity retail markets as in, for example, the initial California market (Wolak, 2003), the PUCT adopted the "price-to-beat"

(PUCT, 2001b) to encourage competitive retail market for residential and small customers. The rule requires a 6% reduction from the rates in effect on January 1, 1999 for residential and small commercial customers (peak demand of 1 MW or less) who choose to take service from the affiliated retail electric provider. However, in contrast to the initial California retail market, the price-to-beat allowed for adjustments based on fuel costs and affiliated REPs could charge above the price-to-beat. These issues will be discussed in the next paragraphs.

The price-to-beat can be adjusted by a “fuel factor” for the integrated utility as of December 31, 2001. The fuel factors are adjusted to reflect changes in the prices of fuel to approximately track average wholesale prices and to prevent the price-to-beat from falling below the wholesale prices. This avoids a problem that arose in California’s retail competition, where the incumbent utilities were required to provide service to retail customers at rates that were below their actual costs to serve customers. On the other hand, the adjustment of rates through a fuel factor means that there are not strong incentives for the affiliated retail electric provider to seek contracts with the most efficient generation plant.

Affiliated REPs are required to sell electricity at or above the price-to-beat to residential and small-commercial customers (1 MW of peak demand or less) until January 1, 2007. They can offer rates lower than the price-to-beat beginning January 1, 2007, or earlier if at least 40% of their customers (1 MW of peak demand or less) move to competitors. Customers who did not choose a new REP were transferred automatically to their utility’s affiliated retail electric provider in January 2002.

The objective of the price-to-beat is to encourage entry of new retail providers for residential and small commercial customers. The price-to-beat freezes the incumbent retailers’ rates at a level that was chosen so that the new competitors should be able to undercut it. The intent was that it would be easy for new competitors to enter the market by providing a large amount of “headroom;” that is, the difference between the price-to-beat and the competitive market price. In contrast, if the rate charged by the affiliated REPs were below the competitive price, then other REPs would be unable to compete for customers and make a profit.

Interestingly, this suggests that, although the rates in ERCOT were low by national standards, the rates were nevertheless well above competitive prices for energy in ERCOT. This simultaneously allows retail price reductions and significant headroom. The situation is evidently similar to the England and Wales experience (Green, 2003). However, it contrasts with the experience in California where retail rate reductions were financed by bonds and did not, apparently, represent a sustainable reduction in prices (Wolak, 2003).

Based on the publicly available information from the REPs, the approved price-to-beat rates, and representative usage levels (calculated using a historical load profile for each service area), the PUCT has estimated that residential customers have saved approximately $900 million on electric bills in 2002 as compared to 2001. Competing REPs were estimated by the PUCT to be offering up to 14% in additional savings off the price-to-beat to residential customers (PUCT 2003e). However, it is difficult to assess the veracity of the PUCT assessment and whether this is a sustainable reduction. For example, as indicated by Joskow (2003), some of the savings are due to issues that would have occurred in the absence of restructuring and, moreover, the large reserve margins in ERCOT now suggest over-building of generation and, consequently, relatively low wholesale prices if the market were functioning efficiently. Retirements of generation may increase wholesale prices and retail prices in the medium term.

Whatever the long-term prognosis for the market, customers have taken advantage of the opportunities to switch providers. As of February 2003, about 467,029 retail customers were taking service from non-affiliated REP. Over 7% of residential customers were served by a non-affiliated REP. About 11% of small non-residential and 50% of large non-residential customers (peak demand larger than 1 MW) received service from a non-affiliated REP (ERCOT, 2003a).

The Price-to-beat has enabled retail competition in ERCOT by setting prices for formerly regulated entities that allow competitive retailers to undercut them. It is a transition measure to foster competition in the retail market. As discussed in the context of England and Wales by Green (2003), the incentives for retail customers to switch have come from a regulatory decision to set the headroom to be large. While this has certainly enabled CRs to enter the market, the long-term prognosis is unclear. ERCOT retail prices prior to restructuring were simultaneously relatively low compared to other regions in North America and (given the implication of large headroom) nevertheless well above competitive levels. This combination is potentially unique to ERCOT.

3.11 Load Response

QSEs can, in principle, bid their load resources into ancillary services and other markets as “Loads Acting as Resources” (LaaR). Many traditional demand-side resources, however, have found it difficult to meet all of the performance criteria set out in the protocols all of the time. Consequently, the number of LaaRs that can compete in the provisioning of the services has been low, resulting in a less competitive market than would otherwise be the case. Larger QSEs have an advantage over smaller QSEs due to their superior ability to use load diversity to smooth out performance and have more chance to bid in their LaaRs.

Some market participants think this situation can be ameliorated by defining a reasonable performance criterion to recognize the unique operating characteristics of fluctuating loads.

Others think a better mechanism is needed so that retail customers can access and respond to real-time prices by either increasing or decreasing their usage as prices increase or decrease.

The importance of incorporating demand response into electricity markets has been observed (Borenstein, 2001). However, implementing demand responsiveness poses challenges because of the difference between generation resources and load, particularly regarding dispatchability.

3.12 Revisions to ERCOT Market

In the process of the ERCOT Protocols review, Dr. Oren, senior consultant of the PUCT, made recommendations in his report to the PUCT regarding market power mitigation, congestion management, simultaneous auction of TCRs, relaxed balanced scheduling, and simultaneous auctions for the ancillary services (Oren, 2000, 2001). All the recommendations have been adopted by the commission as part of the final approval of the protocols with the exception that the congestion management recommendation (for assignment of inter-zonal and local congestion) was predicated on a $20 million trigger in re-dispatch cost over a 12 month. When the PUCT approved the ERCOT Protocols in June 2001, it was decided to phase all the recommended changes gradually.

Subsequent to the approval of the ERCOT Protocols, the Protocols have undergone significant changes to improve the wholesale market, including the changes that were anticipated in the June 2001 Protocols. Between 2001 and 2003, there were about 130 Protocol Revision Requests (PRRs) approved by the ERCOT Board. Among these, the PRRs of direct assignment of zonal congestion rent (section 3.3.3), relaxed balanced schedules (section 3.1.2), and simultaneous selection of ancillary services (section 3.4) are three of the major revisions to the

ERCOT market. Figure 11 shows the milestones and principal revisions to the ERCOT market. In the future, ERCOT will change from a zonal to a nodal market.

[Figure 11: Milestones and Revisions of the ERCOT Wholesale Market]

The large number of rule changes and amendments in ERCOT are potential barriers to entry into the ERCOT wholesale market. Only large companies were able to track, discuss, and implement rapid changes in a timely fashion. The level of changes has potentially discouraged some new entry. Although it was important to correct the deficiencies in the market, it may have ultimately been better to spend more time developing the market in advance of implementation to minimize the necessity for changes. In some cases, such as the problems with uplift charges, experiences from other markets such as California were not heeded in the initial implementation although they were anticipated to be problematic.

3.13 Comparison to other markets

In Table 1, we summarize the current ERCOT market design versus other US electricity markets in relation to day-ahead, hour-ahead, and real-time energy markets, congestion management and other attributes. The markets listed in the table are ERCOT, those of the California Independent System Operator (CAISO) MD02, the New York Independent System Operator (NYISO), ISO New England (ISO-NE), the Midwest Independent System Operator (MISO), Pennsylvania-New Jersey-Maryland (PJM), and the FERC SMD.

Table 1 shows that there are various differences in detail between all markets such as, for example, the presence of an hour-ahead market and the market mitigation procedure. However, a striking aspect of Table 1 is that the markets besides ERCOT are similar in a number of aspects while the ERCOT market is different to them all. The ERCOT market demonstrates, for example, that an electricity market can be run without central day-ahead dispatch, albeit with implications such as limited price discovery and potential operational inefficiencies. It also demonstrates that a market can function with a zonal rather than a nodal congestion management system; however, again there are implications for operational efficiency.

[Table 1: Summary of Major U.S. Electricity Market Design]

4. Summary of lessons learned and conclusion

This paper presented a review of the electricity market development in ERCOT and the lessons learned from the market experience. In this section, we conclude by summarizing in point form the lessons discussed in section 3.

- The successful operation of the ERCOT market shows that an electricity market can be run without a centrally dispatched day-ahead market, at least given the current availability of generation and the affiliation between generators and retail providers in ERCOT. This observation should be tempered with the understanding that the market has been operating for only about two years. For example, if supply were to become tighter and transmission congestion more binding then the bilateral scheduling process might be much more problematic. An important aspect of mitigating the effects of market concentration in ERCOT is the implicit vesting contracts due to the affiliation between Resources and LSEs. As more customers move to other CRs in the coming years, the potential for exercise of market power in the wholesale market may increase.
- Portfolio scheduling has provided considerable flexibility to market participants but has several negative implications, including reduced market efficiency, lack of price discovery, limited liquidity, and operational problems. The update of zones on a yearly basis and the lack of long-term financial transmission rights mean that there are transmission congestion risks that are difficult to hedge over long periods.

- The re-dispatch costs experienced in the zonal congestion process and more recently in the local congestion process, show that uplifting re-dispatch costs provides poor incentives to market participants.

- For both the TCR and the Ancillary Services markets, having separate markets for closely inter-related products reduced efficiency.

- ERCOT has attracted considerable independent generation development. Several aspects of the ERCOT market contribute to this, including the availability of natural gas infrastructure, the regulatory environment, having a standard interconnection agreement, and charging only shallow interconnection costs. The last aspect has negative implications in terms of poor incentives for siting generation and has enabled IPPs to inter-connect in advance of adequate transmission capability being built.

- Market power mitigation that aims only at keeping prices low has the side-effect of not encouraging long-term solutions to local market power problems. ERCOT has attracted considerable new independent generation, but for the most part the generation has not located to help with local market power problems.

- The combination of regulated prices being high enough to enable significant headroom and yet low compared to the U.S. average is potentially unique to ERCOT. The price-to-beat has enabled retail competition in ERCOT by setting prices for formerly regulated entities that allow competitive retailers to undercut them. It is a transition measure to foster competition in the retail market.

- Implementing demand responsiveness poses challenges because of the difference between generation resources and load, particularly regarding dispatchability.

- There have been many changes to the ERCOT protocols, potentially posing a barrier to entry.

The ERCOT market continues to evolve. Similarly, the lessons learned from the restructured ERCOT market should be viewed as a work in progress with only two years or so of accumulated experience.

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Appendix

AEP – American Electric Power
AMP – Automatic Mitigation Procedure
AS – Ancillary services
BENA – Balancing Energy Neutrality Adjustment
CAISO – California ISO
CCN – Certificate of Convenience and Necessity
Co-Op – Electric Cooperatives
CPL – Central Power and Light Company
CR – Competitive Retailer
CRE – Closely Related Elements
CSC – Commercially Significant Constraint
CSM – Competitive Solution Method
Entergy – Entergy Gulf States, Inc.
EIA – Energy Information Administration
ERCOT – Electric Reliability Council of Texas
FERC – Federal Energy Regulatory Commission

ICAP – Installed Capacity Market
IMO – Independent Electricity Market Operator of Ontario
IOU – Investor-owned electric utility
IPP – Independent Power Provider
ISO-NE – ISO New England
ISO – Independent System Operator
LaaR – Loads Acting as Resources
LMP – Locational Marginal Pricing
LRS – Load Ratio Share
LSE – Load Serving Entity
MCPC – Market Clearing Prices of Capacity
MCPE –Market Clearing Price of Energy
MD02 – California Market Design 2002
MISO – Mid-West Independent System Operator
MOD – Market Oversight Division
MOU – Municipally Owned Utilities
NEM – National Electricity Market of Australia
NERC – North American Electric Reliability Council
NOIE – Non-Opt-In Entity
NETA – New Energy Trading Arrangement of England and Wales
Nord Pool – Nordic Power Exchange
NSRS – Non-Spinning Reserves Service
NYISO – New York ISO
NZEM – New Zealand Electricity Market
OOMC – Out of Merit Order Capacity
OOME – Out of Merit Order Energy
PARWG – Planning Assessment and Review Working Group
PCR – Pre-assigned Congestion Rights
PDS – Parallel Decoupled Solution
PGC – Power Generation Company
PJM – Pennsylvania-New Jersey-Maryland Interconnection
PRR – Protocol Revision Request
PTC – Production Tax Credit
PUCT – Public Utility Commission of Texas
PURA – Public Utility Regulatory Act
QF – Qualifying Facility
QSE – Qualified Scheduling Entity
REP – Retail Electric Provider
RgDn – Regulation Down Service
RgUp – Regulation Up Service
RMR – Reliability Must Run
RPRS – Replacement Reserve Service
RRS – Responsive Reserve Service
SB7 – Senate Bill 7
SCE – Schedule Control Error
SGIA – Standard Generation Interconnection Agreement

SMC – Simultaneous real-time Market Clearing
SMD – Standard Market Design
SWEPCO – Southwestern Electric Power Company
TCR – Transmission Congestion Right
TCRF – Transmission Cost Recovery Factor
TDSP – Transmission and/or Distribution Service Provider
TNMP – Texas-New Mexico Power Company
TXU – TXU Electric Company
WTU – West Texas Utilities Company
ZEN – Zonal-ERCOT-Nodal

Figure1: Regional Reliability Councils of NERC

Source: www.nerc.com

Figure 2: Available Resources and Peak Demand of ERCOT (1996 - 2002)

Source: NERC, 2003

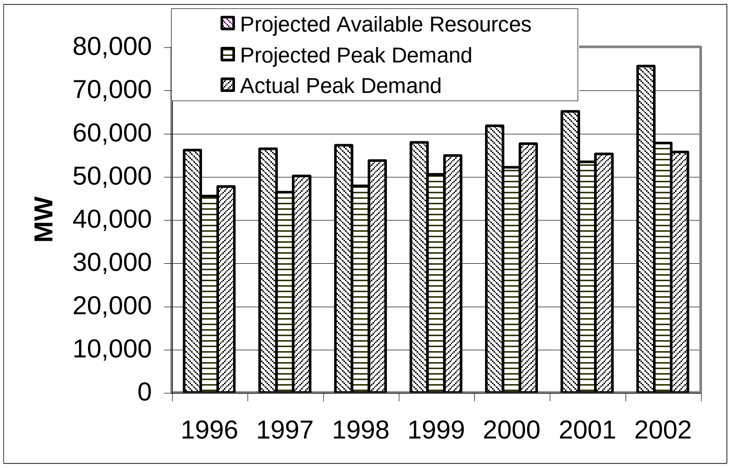

Figure 3: Overview of ERCOT Market Participants

Source: ERCOT 2001

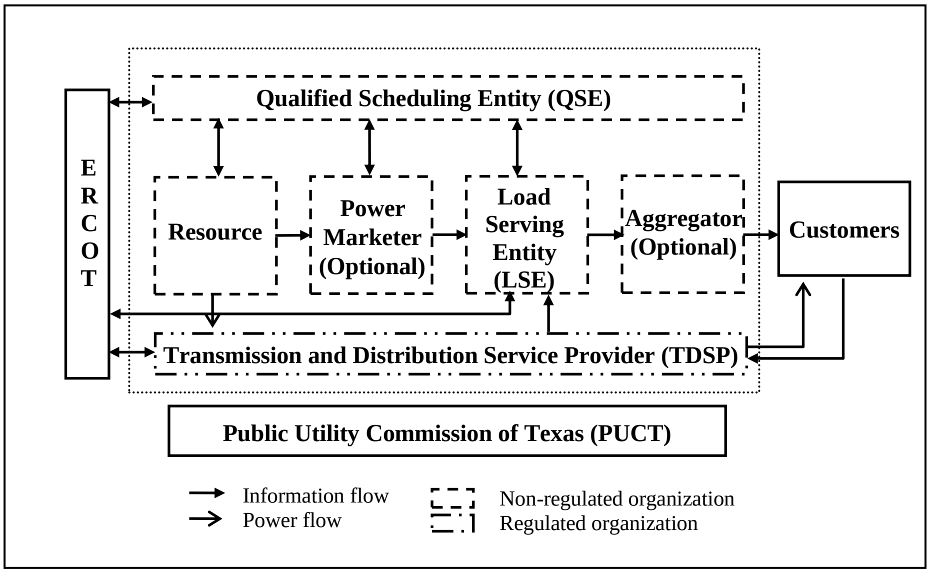

Figure 4: A two zone system

Source: Oren, 2003

Figure 5: Congestion Costs and Rents

Source: Oren, 2003

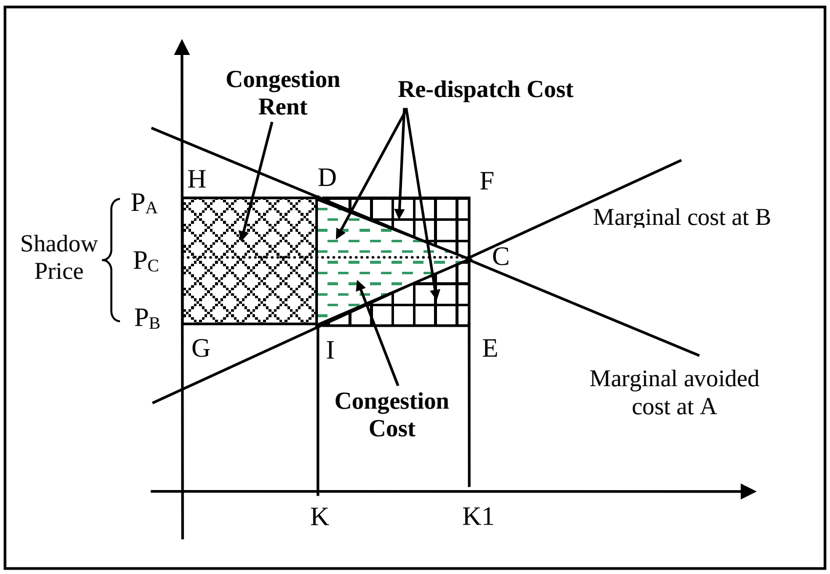

Figure 6: CSCs and congestion zones of ERCOT in 2003

Source: ERCOT 2002a

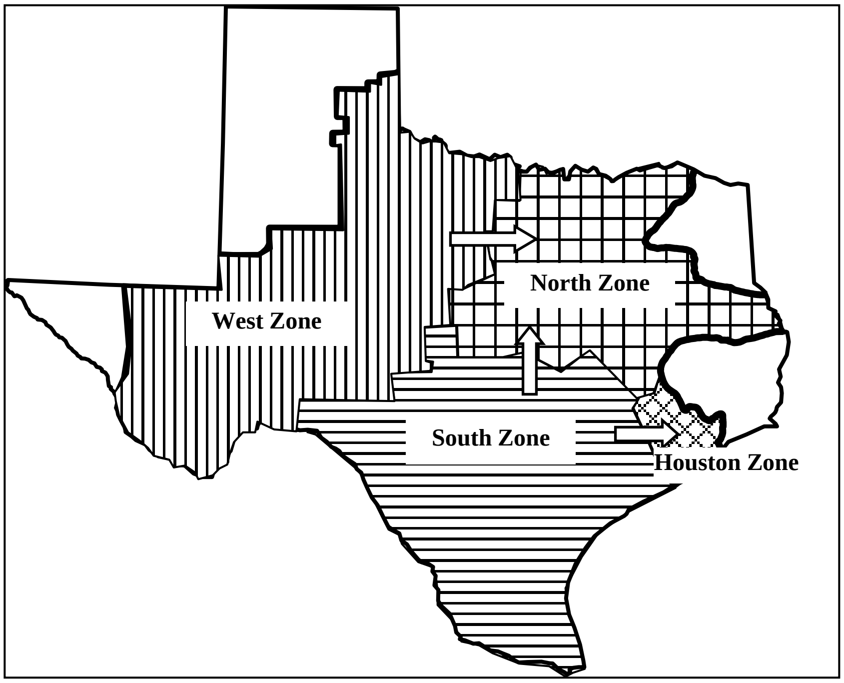

Figure 7: Zonal Re-dispatch Cost (Aug. 1, 2001 – Feb. 14, 2002) and Congestion Rent (Feb. 15, 2002 – Dec. 30, 2002)

Source: ERCOT, 2003c

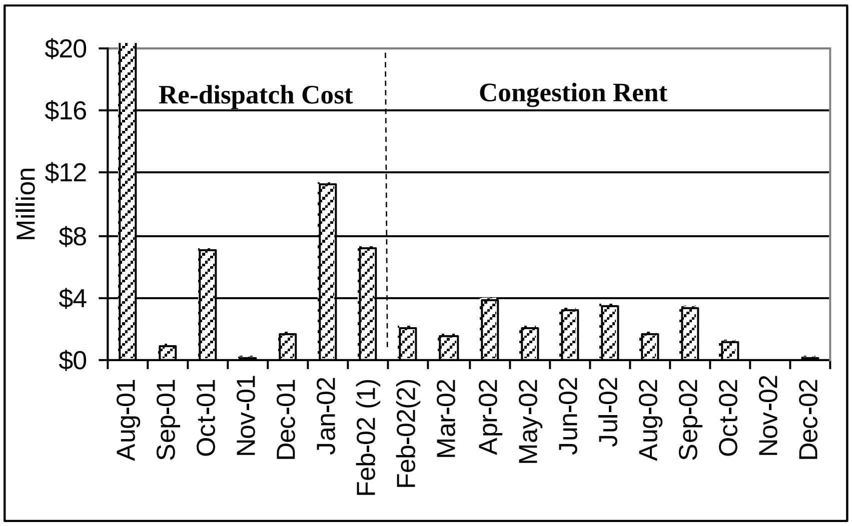

Figure 8: Local Re-dispatch Cost of ERCOT

Source: ERCOT, 2003c

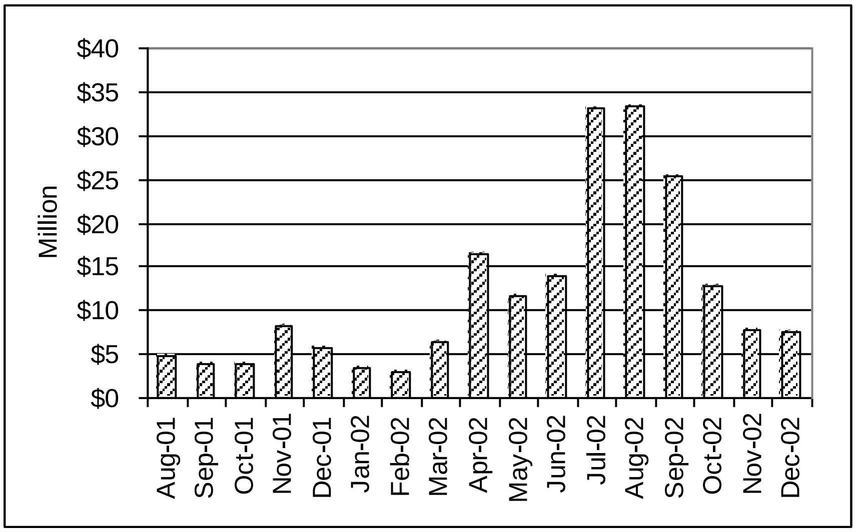

Figure 9: Generation mix in Texas

Source: PUCT, 2003a

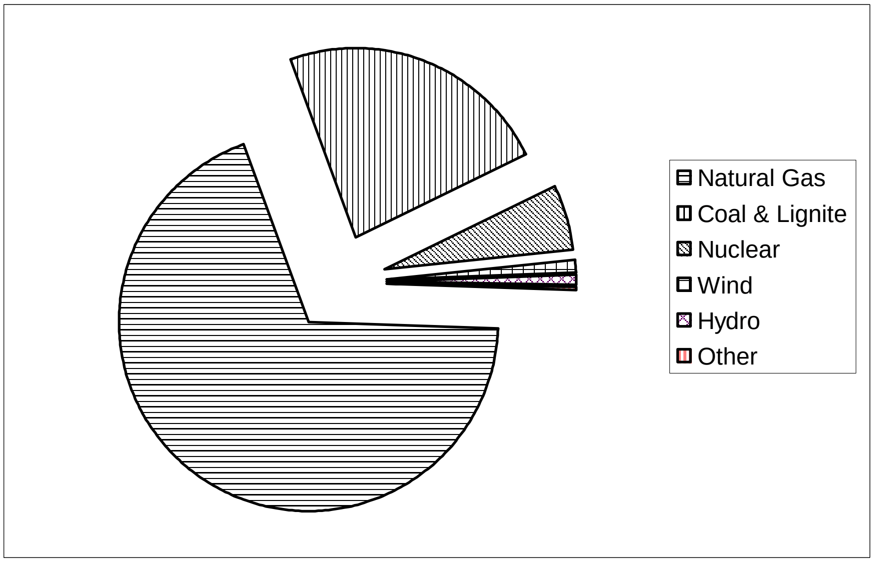

Figure 10: Summer Peak Demand, Capacity and Resource

Source: ERCOT, 2002b

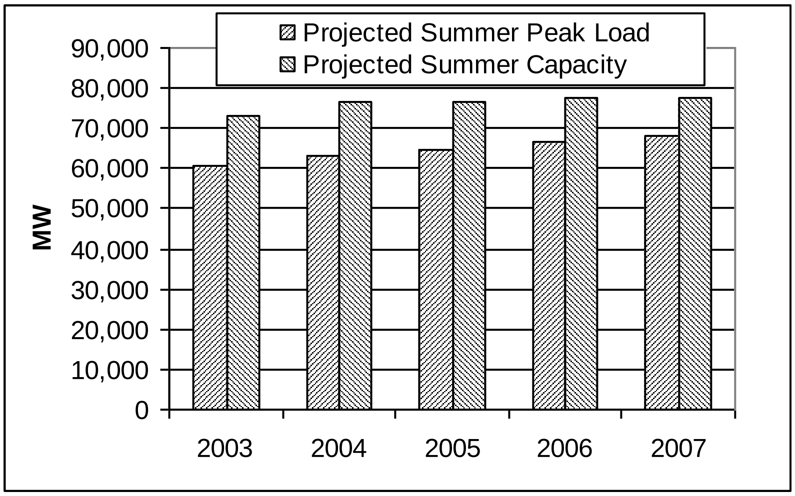

Figure 11: Milestones and Revisions of the ERCOT Wholesale Market

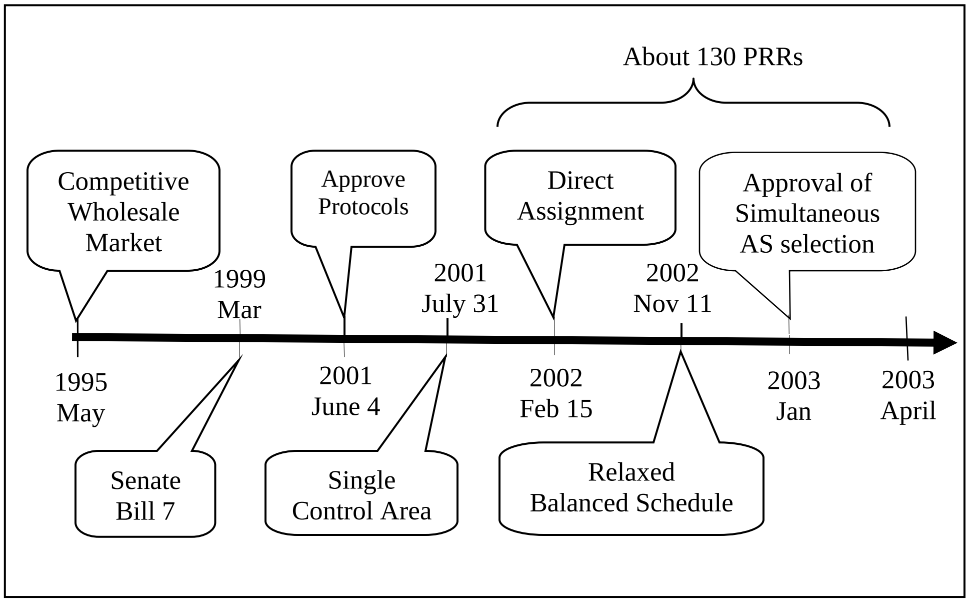

Table 1: Summary of Major U.S. Electricity Market Design

Source: PUCT, 2003b

Market	**Day-ahead Market**	**Hour-ahead Market**	**Real-time Market**	**Congestion Management**	**ICAP Market**	**Price/Bid Cap**	**AMP**
ERCOT	Schedule		√	Zonal/flowgate		√	
California MD02	√	√	√	Nodal	√	√	√
ISO-NE	√		√	Nodal	√	√	
MISO	√		√	Nodal/flowgate	√	√	√
NYISO	√	Schedule	√	Nodal	√	√	√
PJM	√		√	Nodal	√	√	
SMD	√		√	Nodal	√	√	√

[1] Restructured U.S. electricity markets identified by their Independent System Operators (ISOs): California ISO (CAISO); Pennsylvania-New Jersey-Maryland Interconnection (PJM); New York ISO (NYISO); ISO-New England (ISO-NE), Electric Reliability Council of Texas (ERCOT). U.S. electricity markets undergoing development or changes: California Market Design 2002 (MD02) and Mid-West ISO (MISO). Examples of international electricity markets: Independent Electricity Market Operator (IMO) of Ontario, Power Pool of Alberta, New Energy Trading Arrangement (NETA) of England and Wales, Nordic Power Exchange (Nord Pool), National Electricity Market (NEM) of Australia; New Zealand Electricity Market (NZEM).

[2] Affiliate means: an entity who directly or indirectly owns or holds at least five percent of the voting securities of another entity; or an entity in a chain of successive ownership of at least five percent of the voting securities of another entity; or an entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by another entity; or an entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by an entity who directly or indirectly owns or controls at least five percent of the voting securities of another entity or an entity in a chain of successive ownership of at least five percent of the voting securities of another entity; or a person who is an officer or director of another entity or of a corporation in a chain of successive ownership of at least five percent of the voting securities of an entity; or an entity that actually exercises substantial influence or control over the policies and actions of another entity; or any other entity determined by the PUCT to be an affiliate.