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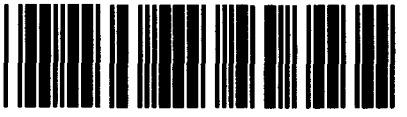

Item Number: 7

Addendum StartPage: 0

Public Utility Commission of Texas

TO: Filing Clerk

FROM: Jess Totten, Electric Industry Oversight Division

DATE: March 3, 2006

RE: Legislative Report, Project No. 32198

Attached for filing is a corrected version of the legislative report that was filed in this Project on February 3.

Electricity Pricing in Competitive Retail Markets in Texas

At a meeting of the Regulated Industries Committee of the Texas House of Representatives on December 12, 2005, Speaker Sylvester Turner requested that the Public Utility Commission prepare a report that answers three questions about electricity prices in Texas. The following day, he sent a letter to the PUC Commissioners, setting out his request. This report is the Commission's response to Speaker Turner's request.

Executive Summary

The principal conclusions reached in this report are the following:

- Service options are available to residential customers in many areas of Texas, including the Houston and Dallas-Fort Worth areas, at prices that are significantly below the estimated rates that would have been in effect if regulation had continued.

- A residential customer in the Houston area who switched to a competitive Retail Electric Provider in January 2002 and switched annually thereafter to the lowest-cost provider would have saved about $1440, compared to the estimated regulated rate, over the four-year period retail competition has been in effect.

- Similarly, a residential customer in the Dallas area would have saved over $800 in the last four years by switching annually to the lowest-cost provider.

- There are benefits of competition beyond lower prices for electricity, such as a variety of service and pricing options and efficient mechanisms for promoting renewable energy and energy efficiency.

- Competitive forces resulted in the replacement of older power plants with new, efficient plants, making a major contribution to the reduction of emissions from the electric industry and progress in meeting national air-quality standards in the Houston-Galveston and Dallas-Fort Worth areas.

- The sale of Texas Genco will not adversely affect the Texas electricity market and will not affect retail prices for electricity.

- Rates charged by other utilities in Texas that do not provide retail competition to their customers are not an appropriate proxy for the regulated rates that would have been in effect if competition had not been introduced.

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The tables below summarize the estimated regulated rates, the average of the five lowest competitive prices, the best competitive price, and the Price to Beat for the CenterPoint and TXU service areas.

CenterPoint Energy Service Area	2002	2003	2004	2005
Estimated Regulated Price	**11.1**	**12.0**	**12.7**	**13.9**
Average of Lowest 5 Competitive Prices (actual)	**8.2**	**9.0**	**9.8**	**11.4**
Percentage Difference from Estimated Regulated Price	*26%*	*25%*	*23%*	*18%*
Best Competitive Price	**8.0**	**8.5**	**9.4**	**10.6**
Percentage Difference from Estimated Regulated Price	*28%*	*29%*	*26%*	*24%*
Reliant Energy Price to Beat	8.8	10.3	11.1	12.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

TXU Electric Delivery Service Area	2002	2003	2004	2005
Estimated Regulated Price	**9.4**	**10.5**	**10.7**	**12.1**
Average of Lowest 5 Competitive Prices (actual)	**8.0**	**8.7**	**9.1**	**10.7**
Percentage Difference from Estimated Regulated Price	*15%*	*18%*	*15%*	*11%*
Best Competitive Price	**7.8**	**8.4**	**8.7**	**10.1**
Percentage Difference from Estimated Regulated Price	*17%*	*21%*	*18%*	*16%*
TXU Energy Price to Beat	8.4	9.6	10.5	11.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

Question 1: Comparison of Regulated and Competitive Rates

In Speaker Turner's letter dated December 13, 2005, he requested "an 'apples to apples' comparison between the cost of electricity today and the cost if the electric market had not been opened to competition."

Developing estimates of what rates would have been if the retail sale of electricity had remained regulated is fraught with uncertainties. The PUC regards any answer that the agency or others provide as an estimate with a large degree of uncertainty, because of the numerous and inter-related assumptions that must be made to perform the calculation. In view of the resources required to perform this analysis, the calculations are limited to the TXU Electric Delivery and CenterPoint Energy service areas. These are the largest service areas open to competition.

With respect to the cost of electricity in today's market, competitive offers are more representative of the results of introducing competition than the Price to Beat (PTB). The PTB is not a competitive rate; rather, it was intended to be sufficiently above market rates to permit new entry into the market by retail electric providers and to encourage customers to shop. The tables above show the best competitive offer and the average of the five lowest offers available in the market as comparison points. These points of comparison provide representative market prices.

The results summarized in the tables above indicate that the competitive market has provided customers with prices that were significantly below the estimated rates that would have been in effect in a regulated environment. Even customers who did not switch to a competitive rate have benefited from the introduction of retail competition. During each of the years 2002 through 2005, the PTB was lower than the estimated regulated rates in both service areas.

Question 2: Impact of Sale of Texas Genco

Speaker Turner also asked whether the sale of Texas Genco would affect the Texas electric market and electricity prices.

The sale of Texas Genco will *not* negatively impact the Texas electric market and will *not* affect market prices of electricity. In a competitive electricity market, a supplier that does not possess market power does not have the ability to set market prices. Instead, prices are determined by the market forces of supply and demand. The value of assets in this environment is based on expectations about the costs and revenues that an asset will generate over its life. Under regulation, on the other hand, the value of an asset is a key factor that is used by regulators in establishing prices for consumers.

The substantial increase in the price of natural gas over the last several years has increased the profitability of coal and nuclear generation, because of the low and stable prices of coal and nuclear fuel. The result has been dramatic increases in the values of coal and nuclear generation assets. Conversely, if substantial decreases in natural gas

prices occurred, the value of solid fuel assets such as coal and nuclear facilities would fall.

Question 3: Current Rates in Non-competitive Areas

Finally, Speaker Turner asked for an analysis and response to Carol Biedrzycki's comparison of the prices of electricity offered by various providers.

Ms. Biedrzycki appears to suggest that deregulating retail rates has resulted in higher rates for customers. The comparative rate information that she provided does not support this conclusion. Rates differed among utilities prior to competition, for a number of reasons, and rates changed in different ways for a number of reasons. One of the biggest factors resulting in the differences in rates and the degree of change in rates is the fuel mix of the generating plants that are used to produce power for customers. Other reasons why the current rates for utilities differ include:

- Different utilities have historically had different rates.
- Senate Bill 7 included a rate freeze that limited the regulated investor-owned utilities' ability to change rates.

Electricity Pricing in Competitive Retail Markets in Texas

Question 1: Comparison of Regulated and Competitive Rates

Speaker Turner's first request was as follows: "Specifically, I am referring to my request for a model that would make an 'apples to apples' comparison between the cost of electricity today and the cost if the electric market had not been opened to competition."[1]

Estimates were made of the cost of electricity for residential customers in the two largest utility service areas in Texas, TXU Electric Delivery Company and CenterPoint Energy. TXU provides delivery service in Dallas-Fort Worth and large parts of North, West, and Central Texas. CenterPoint provides service in Houston and surrounding areas. The estimated cost of electricity under regulation is compared to representative competitive rates in each service area. The PTB is also provided as a reference point, but it is not the appropriate comparison point to the estimated regulated rates, as discussed below. In addition, this response provides a discussion of the differences between a regulated market and a competitive market, information on the benefits of competition, apart from any cost considerations, and a description of the process used to estimate the rates that would have been in effect if electric service had remained regulated. This analysis is limited to residential customers, because both regulated and competitive prices vary widely for commercial and industrial customers based on their size, energy use patterns, their ability to curtail their demand, individual contract terms, and other factors.

[1] This and the other questions are quoted from the letter from Rep. Sylvester Turner to Chairman Paul Hudson, Commissioner Julie Parsley, and Commissioner Barry Smitherman, dated December 13, 2005.

Estimating hypothetical regulated rates for a period of several years is a difficult task at best. The largest component of regulated electricity rates is the cost related to the ownership and operation of generation plants. Consequently, the amount and cost of generation investment and the cost of fuel are the largest drivers of electric utility rates. The statute that established retail competition led to the unbundling of the existing utilities and the entry into the generating sector of new companies that made large investments in new, efficient generating facilities. Apart from the relatively straight-forward task of determining the prices of natural gas and coal, assumptions have to be made about the kinds of power plants that the utilities would have used to produce power for their customers and the costs of the plants. A regulated environment would have resulted in a different set of generating plants, different costs, and a different cost recovery regime than occurs in a competitive market, and these differences have major implications for estimating the price of electricity.

The legislative adoption of retail competition in 1999 resulted in an extraordinary level of investment in new generating facilities in ERCOT that were more efficient in converting natural gas to electricity than many of the plants owned and operated by the integrated utilities. The result was an extraordinary improvement in the overall efficiency of the power plants in ERCOT. If retail competition had not occurred, new investment in power plants would have been required to meet the needs of Texas electricity customers, but the level of investment would have been much lower, and the improvement in overall power plant efficiency would have been much more modest. The implications for electric rates are that more natural gas would have been consumed to meet customers' needs under continued regulation, more aging and inefficient plants would have remained online, and customers' rates would have reflected these higher costs.

Because of the importance of cost recovery related to investment in generation facilities and fuel costs, a discussion on the different treatment of these costs in a regulated world and a competitive world may be helpful.

Comparison of Regulation and a Competitive Market

Competition in the sale of electricity was introduced in Texas in two stages, in the wholesale market in 1995 and in the retail market in 2002. The market changes occurred at a time when the State was facing increasing demand for electricity and the need to build additional power plants. It was also a time when customers were beginning to pay higher electricity prices associated with the completion and commencement of operation of large nuclear-generating plants. One of the major impacts of the introduction of competition was to shift the risk associated with building new power plants from customers to the companies that built the new plants. Billions of dollars were invested to build new plants to meet the needs of Texas customers, and the companies that built the plants bore the risk of recovering the cost of these plants through market-based prices.

In a regulated environment, the risk of investment in new generation facilities rests primarily on customers. The rules of rate regulation require utilities to provide adequate, reliable service to their customers, and rates are set to allow them to recover their prudent

investments with a reasonable rate of return. New production facilities are subject to pre-approval and a post-construction prudence review, and in this process the utility must demonstrate that its proposed facility is needed, is the option that will best meet customers' needs, and that the costs were prudently incurred.

In theory, these regulatory approvals would ensure that the utility acquires a facility only when it is needed, selects the most appropriate technology, and manages the construction of the facility to minimize its cost. In reality, a regulatory commission and the parties who participate in these proceedings face significant difficulties in challenging the utility on its choice of technology or its management of the construction process. Additionally, since review of the costs occurs after the fact, significant disallowances may threaten the utility's financial integrity. Because cost recovery is set for the life of the asset, customers are generally locked into paying for the investment, even if subsequent technologies or changes in fuel or energy markets make the investments uneconomic. When utilities in Texas constructed the South Texas Project and Comanche Peak nuclear power plants, the projects experienced significant cost overruns, and the prudence reviews resulted in relatively small disallowances of construction costs. The costs of the South Texas Project are a major component of the stranded costs that CenterPoint Energy and AEP Texas Central Company will be recovering from customers in their service areas.

In a competitive environment, on the other hand, investors in new generation are not assured of the recovery of plant costs from customers. A company that invests in new generating facilities bears the risk that the facility will recover its costs through sales in the market. In ERCOT, as the new generating facilities began operating and retail competition began in 2002, the wholesale market prices for power indicated that these new plants were not making substantial margins on the sale of the power that they produced. Nevertheless, the new, efficient power plants operated, and the market prices were based on their efficiency. In the early days of competition, electricity customers got the benefit of market-priced electricity from these efficient generating plants without paying their full capital costs.

Competition also provides stronger incentives for producers to operate their generating plants efficiently. In a regulated environment, the utility recovers its fuel costs through rates. The regulatory commission periodically reviews fuel costs and power plant operations to ascertain whether the utility has operated efficiently, and it can disallow costs that it concludes are higher than would result from efficient operations. In a regulatory review, the utility has the important advantages of both greater resources and better knowledge of how its plants have operated.

In a regulated environment, there is not a direct connection between efficiency and profitability. If the utility is inefficient, and the regulatory commission is not able to detect the inefficiency, the utility recovers all of its fuel costs and does not experience any consequences from its inefficiency. If the utility is able to increase its efficiency and reduce fuel costs, the commission would reduce the rate, and customers would benefit from the improvement. On the other hand, in a competitive market, the producer's

revenue is based on market prices, not commission-established rates, and any increase in efficiency can lower production costs and increase profits. In competitive markets, operators of coal and nuclear power plants have been able to increase the number of annual operating hours of their plants. Because these are plants with low operating costs, increasing the number of operating hours enables the operators to increase their profitability. Thus, profit motivation provides a strong incentive for producers to improve efficiency.

Under regulation, rates are set to recover the utility's investments and expenses from customers by grouping customers with similar characteristics into large classes. For certain expenses, such as fuel, a rate is set based on forecasted costs, and then reconciled with actual expenses at a later date. While this provides a customer assurance of the level of prices for a short period, the customer is required to bear the risk associated with changes in fuel prices. If fuel prices increase, the increases are passed on to customers through a surcharge, and customers have little ability to contract with the utility in a way to obtain price certainty.

Retail competition brings a broader array of pricing options to customers. The Texas retail market is still quite young, but business customers have a number of pricing options, particularly with respect to the allocation of risk of changes in market prices. In the competitive environment, a customer typically can find a price that is fixed for some period of time or a can choose a rate that is adjustable, depending on market conditions, on an hourly, daily, or monthly basis. Changes in market conditions spur REPs to develop pricing options to meet customers' expectations. For example, after the increase in natural gas prices in the late summer and fall of 2005, many retailers and customers expected gas prices to fall, as production was restored at gas production facilities that were taken out of service as a consequence of Hurricanes Katrina and Rita. In this market, some REPs developed pricing plans that gave customers a long-term contract at a rate that could not be raised but could be lowered, if falling gas prices result in lower prices for electricity in the wholesale market. In addition to options related to price risks, an option that is broadly available in the retail market is renewable energy.

Historically, this variety of pricing options has not been available in a regulated environment, because of the difficulty of ensuring fair prices. The retail market ensures, through market forces, that options related to price risk and renewable options are appropriately priced. A regulatory commission typically does not have the resources to assess the costs and risks associated with multiple service options and appropriately establish and modify the prices, based on evolving market conditions. These are valuable options to customers that would be virtually impossible to provide in a regulated environment.

Competition also allows REPs to bundle electric service options with other services in packages that customers find attractive. Competition is in its infancy in Texas, and REPs have focused on establishing their businesses and winning customers. As competition matures, it is likely that REPs will combine electric service with other services in packages that customers find attractive. Indeed, certain REPs are already offering

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appliance-repair and HVAC-servicing plans that are designed to foster energy efficiency. In an environment in which electricity prices have increased, it seems particularly likely that REPs will offer further energy-efficiency services to help customers reduce their energy costs.

Finally, the implementation of retail competition has provided benefits to society at large. These forces of competition resulted in a significant shift in electricity production away from older, less efficient power plants to new, more efficient power plants. At a time when the State faced a serious problem in meeting national air-quality standards in the Houston-Galveston and Dallas-Fort Worth areas, the new power plants made a major contribution to reducing emissions from the electric industry. Senate Bill 7 included measures that were explicitly intended to contribute to cleaner air. Competition also provided an efficient mechanism for meeting goals for renewable energy and energy efficiency, which have contributed to reducing emissions of nitrogen oxides, one of the precursors for ozone formation. Among the provisions of Senate Bill 7 was a requirement that utilities assess a system benefit fee, which would be used to provide discounts and energy-efficiency improvements to low-income customers. In the four years that appropriations for the low-income discount were made, REPs provided low-income customers over $300 million in discounts.

Method for Estimating Regulated Rates

Estimating the rates for a hypothetical situation that did not occur is a difficult task. The estimate requires information about the costs incurred by utilities and prices for natural gas and coal. Some of these costs are likely to have been the same, whether competition was introduced or not. Other costs are dependent on events that would certainly have been different in a regulated environment, and there may be a large degree of uncertainty about how events would have unfolded.

The other difficulty is the need to simplify the process of estimating rates. Rate cases involve the review of a large volume of information over a period of months and legal and factual arguments among the parties to the rate case over whether some of the expenses that the utility seeks to recover were reasonable and necessary. At the end of the rate case, the PUC decides which expenses are reasonable and necessary and what rate of return is appropriate. This is an event that cannot be replicated in estimating the rates that would have been in effect. The estimate that is provided here is based on the best information that could be gathered in a relatively short time and an assessment of how the utilities might have met their customers' needs.

The methodology used to estimate the regulated rates was to assume that new base rates were set for the two utilities in the 2000-2001 timeframe, and that these base rates would have remained in effect through 2005. It is assumed that rates for the recovery of fuel and purchased power, however, would have been adjusted to match the changes in fuel costs in the market and increased purchases of power to meet the utilities' needs. There are a number of simplifications and uncertainties that are involved in using this methodology that are likely to result in differences from what would have actually

occurred, if regulation had continued. For example, a different level of transmission investment might have been required, and the Legislature or PUC might have adopted renewable energy requirements that are not reflected in the estimate of regulated rates that is included in this report. Such uncertainty would be present in any effort to estimate the rates that would have been in effect in a regulated environment.

The starting point for estimating the rates that would have been in effect are the annual reports that utilities filed in the 2000-2001 timeframe. The annual reports are mandated by PURA, constitute an abbreviated calculation of utility costs, and provide contemporaneous information about the utilities' costs. In addition, in estimating the regulated rates, an assessment was made whether the utilities would have needed to acquire additional capacity and energy to meet their customers' needs and whether they would have made investments in pollution control equipment for existing generating plants. Senate Bill 7 required that utilities meet more stringent air pollution standards, but it is assumed that the need to improve air quality in major Texas cities would have resulted in more stringent standards, even if Senate Bill 7 had not been enacted.

This approach assumes that utilities would have generated the electric energy needed to serve their customers first from the fleet of generating plants that they owned before competition began. To the extent that a utility would have needed to acquire additional capacity and energy to meet its customers' needs, it is assumed that the utility would have met this need by buying power from independent power producers through long-term contracts that would provide the seller recovery of the operating and ownership costs of new generating facilities. A detailed description of the method used for estimating the regulated rates is set out in Appendix 1.

Method for Calculating Competitive Prices

Summarizing the competitive prices that actually existed during the last four years is a far more straightforward exercise. The PUC performs a survey of residential competitive offers each month and posts that information on its website. This information provides a historical record of the prices available to customers in the marketplace, and was compiled for the TXU Electric Delivery and CenterPoint Energy service territories for each month in the years 2002-2005. The following are provided as representative competitive prices: an annual average of the five lowest competitive offers each month, an annual average of the best competitive price each month, and an annual average of all of the non-renewable products each month. The average of the five lowest competitive offers removes the effects of renewable energy products, which are priced at a premium to other competitive offers, and avoids over-reliance on abnormally low competitive prices offered by competitive REPs whose business models may have been unsustainable.

The PTB, which is the residential rate for customers who did not switch to a competitive Retail Electric Provider, was not used as the principal comparison rate to the estimated regulated rate. The PTB took effect in January 2002 as a rate that was 6% less than the regulated rates in effect in 1999 (adjusted for 1999-2001 changes in fuel costs), and it can be adjusted up to twice per year based on significant changes in the market price of

natural gas and purchased energy, which are highly correlated in ERCOT. The PTB was intended to be, and generally has been, an above-market rate that provides an opportunity for the incubation of new entrants in the retail market during a transitional period. The presence of these new-entrants in turn, gives customers an opportunity to shop for alternate providers. Since 2005, the affiliated REPs have been able to charge prices other than the PTB.

Results

The tables below show the estimated regulated rates and representative competitive prices, in cents per kilowatt-hour on an annual basis, for a typical customer consuming 1,000 kWh each month. The representative competitive prices are the yearly average of the five lowest competitive prices, an average of the best competitive price for each month, and an average of all non-renewable competitive prices. For reference, the average PTB for each year is also shown.

TXU Electric Delivery Service Area	**2002**	**2003**	**2004**	**2005**
Estimated Regulated Price	**9.4**	**10.5**	**10.7**	**12.1**
Average of Lowest 5 competitive Prices (actual)	**8.0**	**8.7**	**9.1**	**10.7**
Percentage Difference from Estimated Regulated Price	*15%*	*18%*	*15%*	*11%*
Best Competitive Price (actual)	**7.8**	**8.4**	**8.7**	**10.1**
Percentage Difference from Estimated Regulated Price	*17%*	*21%*	*18%*	*16%*
Average of all Competitive Prices, excluding renewable products (actual)	**8.1**	**9.1**	**9.6**	**11.7**
Percentage Difference from Estimated Regulated Price	*13%*	*13%*	*10%*	*3%*
TXU Energy Price to Beat	8.4	9.6	10.5	11.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

CenterPoint Energy Service Area	2002	2003	2004	2005
Estimated Regulated Price	**11.1**	**12.0**	**12.7**	**13.9**
Average of Lowest 5 competitive Prices (actual)	**8.2**	**9.0**	**9.8**	**11.4**
Percentage Difference from Estimated Regulated Price	*26%*	*25%*	*23%*	*18%*
Best Competitive Price (actual)	**8.0**	**8.5**	**9.4**	**10.6**
Percentage Difference from Estimated Regulated Price	*28%*	*29%*	*26%*	*24%*
Average of all Competitive Prices, excluding renewable products (actual)	**8.4**	**9.6**	**10.2**	**12.3**
Percentage Difference from Estimated Regulated Price	*24%*	*21%*	*20%*	*12%*
Reliant Energy Price to Beat	8.8	10.3	11.1	12.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

Competitive prices have generally been substantially lower than the estimated regulated rate, illustrating that customers who elected to switch received substantial savings compared to what continued regulation would have provided. Customers who did not switch also benefited from the introduction of retail competition. The PTB was lower than the estimated rate that would have been in effect under regulation for the entire period from 2002 through 2005.

An estimate was also made of the total amount that a typical residential customer would have paid from January 1, 2002 to December 31, 2005 if regulation had continued. This amount was compared to the electricity costs of a hypothetical customer who switched to a competitive provider on January 1, 2002, and then switched on January 1 of each subsequent year to a lower-cost provider, if there was a lower-cost provider. This calculation did not assume that the rate was fixed, but that the rate changed at the same time that the provider altered its pricing in the market. This analysis indicated that a customer in the Dallas area who evaluated the choice to switch annually would have saved over $800 compared to the estimated regulated rates for the four year period that competition has been available. The customer would have also saved over $540 compared to the PTB over the same period. A customer who acted the same way in the Houston area would have saved $1440 over the four year period from the estimated regulated price, and $640 compared to the PTB. Customers who switched more frequently than annually or entered into a fixed price contract for some duration could have saved even more.

Question 2: Impact of Sale of Texas Genco

Speaker Turner's second request was as follows: "What effect does the sale of Texas Genco have on the Texas electric market and how will it affect electricity prices?"

The sale of Texas Genco will *not* negatively impact the Texas electric market and will *not* affect market prices of electricity. While issues underlying this response are explored in greater detail below, the simple answer is based on the fact that, in a competitive electricity market, a supplier that does not possess market power does not have the ability to determine market prices. This is a consequence of how competitive markets operate, and the fact that the sale of electricity in ERCOT is now a competitive market, in which prices are determined by the market forces of supply and demand. The prices in a competitive market are established in a manner that is markedly different from how they are established in a regulated environment. Under regulation, the value of an asset is a key factor that is used by regulators in establishing prices for consumers.

The question arises, of course, whether the sale of Texas Genco would give the new owner the ability to exercise unreasonable market power and consequently influence market prices in an inappropriate manner. Controlling improper exercise of market power was a matter of significant concern on the part of the Legislature when the retail competition law was enacted in Texas, and the law includes a number of provisions to prevent the accumulation and exercise of market power. The sale of the Texas Genco assets did not result in any increase in market power, because the new owner does not own other generating assets in ERCOT.

It would be expected that the sale of generating assets, such as the sale of the Texas Genco assets, would be at a market-determined price, which would be based on two factors: (1) the expected revenues that could be derived from selling the output at *market* electricity prices and (2) the cost of producing the electricity. In other words, the value is based on the expected profits the asset can generate. In the sale of a long-life asset such as a generating plant, expectations about the profit it might generate over its life would determine its value. For a company like Texas Genco, which has substantial coal and nuclear assets, the focus of an analysis of asset value is on revenue. The costs of coal and uranium fuel have historically been quite stable, but electricity prices in ERCOT (and in general) are more volatile.

Market prices in ERCOT in the near term are driven by customer demand and the price of natural gas. Market prices are established by demand and the deployment of the generating plants in the market to meet the demand. In ERCOT, for most of the hours of the year, the available plants with low operating costs, namely, nuclear, coal, and lignite plants, are fully deployed before the aggregate level of customer demand is met. Additional generating plants fueled by natural gas must be used to meet the aggregate demand. Thus, the market-clearing price is established by gas-fired generating plants. The substantial increase in the price of natural gas over the last several years has increased the profitability of coal and nuclear generation, because of the low and stable prices of these fuels. The result has been dramatic increases in the values of coal and

nuclear generation assets. Conversely, if substantial decreases in natural gas prices occurred, they would reduce the value of solid fuel assets such as coal and nuclear facilities.

In the long term, it would be expected that coal and nuclear plants could be built to compete with the existing power plants in ERCOT, and the competitive advantage of the existing coal and nuclear plants would be reduced. Some companies have announced plans to build new coal plants in ERCOT, but there are environmental and financing risks associated with coal and nuclear generation, and the financial sector appears to be skeptical about significant additions of coal and nuclear generation in ERCOT. If new coal and nuclear facilities are built, licensing and construction will take some time. Thus, even in the long-term, ERCOT electricity prices are likely to be highly dependent on gas prices.

In a competitive electricity market, the risk of fully recovering an investment in generation assets falls upon the *purchaser* of the assets, not on customers. This point illustrates a key distinction between regulated and competitive markets: in a regulated environment, the risk essentially falls upon customers, who pay for the asset through rates determined by the rules of cost-of-service regulation. In contrast, in a competitive environment, the risk falls upon the owners of the assets. In competition, any changes in asset value resulting from changes in the market accrue to the owner of the assets. Accordingly, the fact that NRG Energy recently agreed to pay approximately $8.3 billion for Texas Genco does *not* mean that the burden of recovery of this amount falls on the shoulders of customers. Rather, NRG now bears the risk of recovering its investment in Texas Genco, and if the market changes in a way that causes the value of Texas Genco to decline, NRG bears the loss, not customers.

Other Issues Related to a Sale of Assets

To provide greater detail concerning the impact of the sale of Texas Genco, two questions are explored below:

1) Does the sale price of a generation asset drive electricity prices?
2) Does the sale of generation assets bestow upon the purchaser an inappropriate degree of market power and, therefore, the ability to unreasonably influence market prices?

1. Does the sale (and sale price) of a generation asset drive electricity prices?

One of the basic principles for the regulation of rates by a government agency is that customers' prices set by the regulatory agency are based on the cost of providing the service. This basic ratemaking principle allows a utility company to recover the reasonable and necessary expenses of providing the service, plus a return on the investment it has prudently incurred to provide the service. Thus, where assets are used in providing the service to customers, the rates the utility may charge to customers provide it an opportunity to recover the operating costs, including depreciation, and the investment cost, that is, a return on the value of the assets. The costs incurred by the company to acquire an asset are returned to it, over the life of the asset, through the

depreciation expense, and a return on the value of the asset is provided to compensate the company for the risks and financial costs that arise because the recovery is spread over the life of the asset. Accordingly, under traditional regulatory laws and practices, the cost of an asset does have a direct impact on the company's regulated rates. For example, if an asset costs $100, this amount will be expressly reflected in the calculation of the depreciation expense and return, amounts that ratepayers pay over the life of the asset. In this regulated context, asset costs drive the prices that consumers pay, and the higher the prudent cost of an asset, the higher the regulated rates will be.

In contrast, in a competitive environment, the reverse relationship holds true. That is, in a competitive environment, asset values are driven by the expected revenues that the owner of an asset can expect to receive from ownership of the asset over its useful life. This relationship is fundamental for the valuation of any type of asset in a competitive market. With respect to the competitive electricity market, this means that market electricity prices, as determined by market supply and demand, are key determinants of the value of an asset. Reports prepared by analysts in the financial sector support the proposition that the value of companies and their assets in a competitive environment is based on expected revenues. For companies in a competitive environment, such reports focus on the fundamentals of supply and demand and a company's expectations for revenue in the market. Applying these principles to the ERCOT electricity market is relatively straight-forward, because the marginal cost of electricity is based on the price of *natural gas* more than 90% of the time.[2]

Impact of Natural Gas Prices on the Value of Texas Genco

In July 2004, CenterPoint Energy announced the sale of the Texas Genco assets to *Texas Genco LLC* (an entity owned in equal parts by affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P., and Texas Pacific Group) for a total price of approximately $3.65 billion, based on an average stock price of approximately $45.58 per share.[3] This price was based upon then-prevailing expectations of power prices and the revenues that were expected to result from those prices. The purchasers determined that $3.65 billion was the present value of Texas Genco's future margins from the sale of electricity, which were largely predicated upon the forward prices of natural gas and its role in establishing future electricity prices in ERCOT.

In connection with the CenterPoint true-up proceeding before the PUC, J.P. Morgan performed an analysis that used the valuation principles discussed above. The purpose of this analysis was to determine whether a control-premium value accrued to CenterPoint as the majority owner of Texas Genco and, if so, the amount of the premium.[4] The PUC

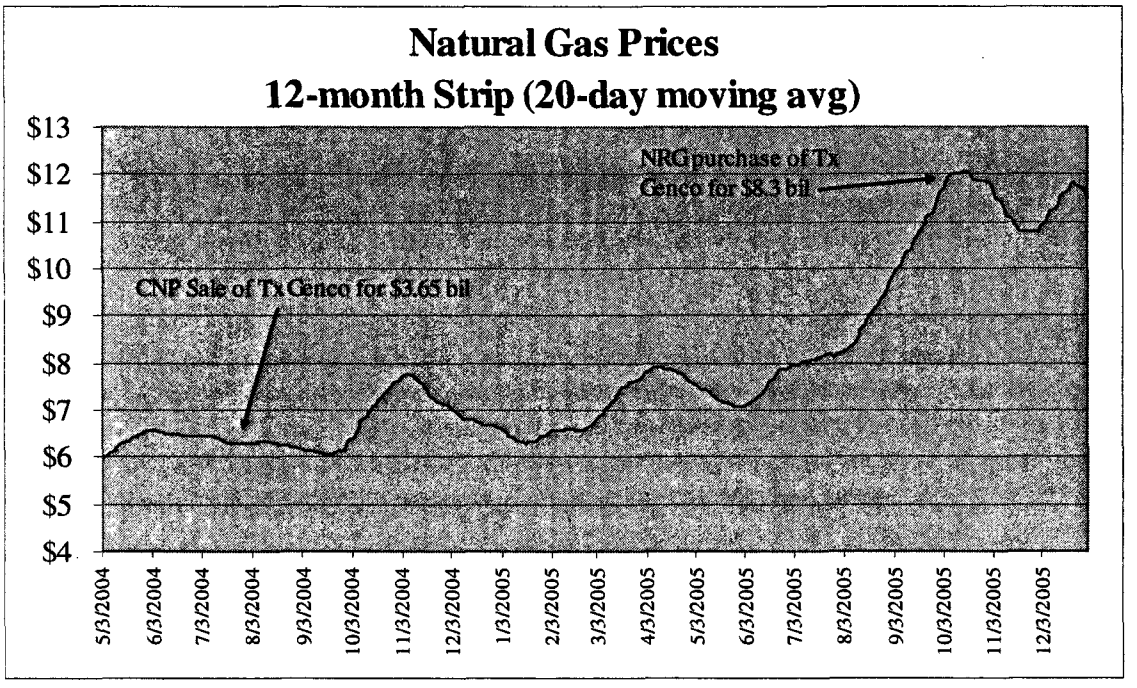
[2] Attached is an analysis of the sale of Texas Genco to NRG by Prudential Equity Group LLC, which addresses a number of the valuation issues covered in this report.

[3] A price of $45.25 per share was paid for CenterPoint's 80.96% ownership, while a price of $47 per share was paid for the 19.04% of shares that were publicly traded.

[4] CenterPoint prepared its true-up filing using the "partial stock valuation" method described in PURA § 39.262 to value its generation assets. For this valuation method, PURA permits the PUC to select an

selected J.P. Morgan to perform this evaluation and, through a variety of valuation techniques, including comparable sales and discounted-cash-flow (DCF) analyses, J.P. Morgan estimated the value of Texas Genco as $42.43 per share. This value was generally consistent with the values paid by *Texas Genco LLC*, as noted above (although the valuation was made at a slightly different point in time from the sale). A critical element of J.P. Morgan's DCF analysis was the expected revenue from the sale of electricity, which was based upon the price of natural gas and the resulting impact on power prices. On page 19 of its report to the PUC, J.P. Morgan emphasized that, "the Valuation Panel also performed a discounted cash flow analysis using such Texas Genco projections as adjusted for changes in the forward natural gas price curves and the implied resultant changes in power prices as of March 31, 2004 (the valuation date)."

Subsequently, in October 2005—approximately 15 months after CenterPoint's sale of Texas Genco to *Texas Genco LLC*—Texas Genco was sold again, this time to NRG Energy. The price paid by NRG was $8.3 billion, substantially higher than the previous sale amount of $3.65 billion. This dramatic difference in value, while occurring over a relatively short period of time, correlates to the increase in the price of gas between mid-2004 and late 2005. The chart below shows the change in gas prices over the period from mid-2004 through the end of 2005:



Not all generation assets would be expected to have their value change in the same way as natural gas prices. The critical factor is whether the change in gas prices affords the

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independent third party to determine whether a control premium should be added to the asset value as indicated by the stock price.

assets a competitive advantage. For the owner of assets that are primarily fueled by natural gas, an increase in natural gas costs would increase both expected revenues and expected costs. The net result might be no increase in expected profitability at all. The Texas Genco assets, however, include a significant proportion of low-cost coal and nuclear generating capacity.[5] As the price of gas has risen dramatically, prices of coal and uranium have been essentially stable. This means that for Texas Genco, current and expected revenues have risen to a greater extent than current and expected costs; accordingly, expected gross margins have risen dramatically.[6]

An example will demonstrate the benefit of increases in the price of natural gas to a company with a coal or nuclear portfolio. If the price of natural gas is $4 per MMBtu, and the market heat rate is 8,000 Btu per kWh, then the market cost of electricity would be $32 per MWh.[7] (That is, 4 * 8000/1000 = 32.) If the cost to a producer of power from a coal-fired generating plant is $20 per MWh, in the $4 gas case, the coal plant would earn a margin of $12. If, on the other hand, the price of natural gas rises to $8, then the new market price of electricity, assuming the same heat rate, would be $64 per MWh. (That is, 8 * 8000/1000 = 64.) In the $8 gas case, the margin to the producer from the energy produced by coal is $44. In this example, while the cost of gas has doubled (from $4 to $8), the margin realized by a coal plant has nearly quadrupled (from $12 to $44). Thus, the values of coal and nuclear assets are substantially magnified by the widening spreads in gross margins as the value of electricity rises.

Notwithstanding the seemingly high price of $8.3 billion paid by NRG for Texas Genco, this amount will not be reflected in any regulated rate and will not determine the value of Texas Genco's production in a competitive environment. Rather, such a high price tag is simply an indication of the current value of the assets as determined in today's marketplace. Whether or not NRG ultimately recovers sufficient revenue to realize a profit on its $8.3 billion investment is dependent upon ever-evolving market conditions and its capability in operating the plants and marketing the output. There is a fundamental difference between the risk of cost recovery in a market environment and the risk in a regulated environment: in a market environment, the risk of cost recovery is borne by the owner of the asset, whereas in a regulated environment, the risk of recovery is largely borne by customers as they pay the cost of an asset through cost-of-service regulation. Consequently, whether or not NRG ultimately receives an appropriate return for its investment is unknown, but what *is* known is that customers are not intrinsically obligated to pay for cost recovery of $8.3 billion. The circumstance in which customers *would* be obligated to pay the cost of the sale of the asset would be a decision by the State

[5] Coal, lignite, and nuclear assets represent only 38% of Texas Genco's total capacity, but these solid fuel assets represent 84% of total energy production and the vast majority of revenue from operations. *Source*: NRG Presentation to Investors, page 11 (available at http://ofchq.snl.com/cache/1500006435.pdf).

[6] Texas Genco's financial reports indicate that a significant portion of its output for the near term has been sold, so that the near-term profitability is not significantly higher, but longer-term expectations of profitability have risen.

[7] The heat rate is a measure of the fuel efficiency of the generating unit. For this example, the unit would require 8 MMBtus of natural gas to generate one MWh of electricity. The market heat rate is the level of efficiency that is implied by comparing the market prices of natural gas and electricity.

of Texas to return to rate regulation. The underlying legal principle of rate regulation is a Constitutional principle: a person may not be deprived of property for public benefit without fair compensation. If regulation were restored to the electric industry in ERCOT, NRG would be entitled to recover the cost of its assets through the regulated rates.

2. Does the sale of generation assets bestow upon the purchaser an inappropriate degree of market power and, therefore, the ability to unreasonably influence market prices?

Stated simply, because NRG did not own any plants in Texas prior to the purchase of Texas Genco, there should be no increase in market power associated with this transaction. The ownership of Texas Genco is simply changing hands, and the transfer of existing assets from one unregulated entity to another has no impact on its ability to exercise market power.

If Texas Genco had been purchased by another major holder of generation assets in Texas, then the purchaser might achieve unreasonable market power and have the ability to improperly influence prices. There are provisions in PURA that deal with market power in a number of ways. One of them is a limit on the total generating capacity that a company may own.[8] Texas Genco is below that limit, and the sale to NRG did not change the percentage of capacity represented by these assets or the percentage owned by NRG. In addition, the law provides for PUC review of certain purchases of generating capacity.[9] If the purchase of generating assets increased the purchaser's ownership of generating capacity to a level that raised a market power concern, the PUC could refuse to approve the purchase or could impose conditions on its approval to minimize the impact on the purchaser's market power. These provisions of the Texas law also illustrate that the focus of public concern in connection with the sale or purchase of assets changes when competition is introduced. In a regulated environment, the law typically requires the regulatory agency to review a sale to determine the impact on rates and services to customers. This review would include a review of the sale price. In a competitive environment, owners of assets would normally have greater latitude to buy and sell assets, and the regulatory review of a sale would focus on how the sale would affect market power.

In a similar development, on January 18, 2006, PNM Resources announced that it had agreed to buy the 305 MW Twin Oaks generating plant from Sempra Energy for $480 million. The generating plant is a lignite plant in Robertson County, Texas, and prior to the purchase PNM Resources did not own other generating facilities in ERCOT. If the sales are compared on a dollar per kilowatt of capacity, including only coal and nuclear capacity, the sales prices for the Sempra and Texas Genco assets are similar. The Genco sale was for about $1590 per kilowatt, and the Sempra sale was for about $1570 per kilowatt.

[8] PURA § 39.154(a).
[9] PURA § 39.158.

Question 3: Current Rates in Non-competitive Areas

Speaker Turner's third request was as follows: "I believe that it would also be beneficial to have an analysis and response to Carol Biedrzycki's comparison between the price of electricity offered by Affiliated Retail Electric Providers and the price offered by selected electric cooperatives and municipally-owned utilities (located on the final two pages of her presentation hand-out)."

One conclusion that Ms. Biedrzycki's hand-out appears to invite is that deregulating retail rates has resulted in higher rates for customers. The comparative rate information that she provided does not support such a conclusion. Rates differed among utilities prior to competition, for a number of reasons, and rates changed in different ways for a number of reasons. One of the important factors resulting in the differences in rates and the degree of change in rates is the fuel mix of the generating plants that are used to produce power for customers. Other factors that affect rate levels are discussed below.

The other conclusion that the hand-outs suggest is that the price increases for customers buying power under the PTB were unnecessary. The Legislature could have decided not to restructure the electric industry or adopt a different approach for doing so, and this might have resulted in different rates today, but the PTB mechanism was a reasonable way to implement the new competition policy. The PTB was intended to achieve a transition to a model of competition in which Retail Electric Providers market their services, and customers make a choice of REPs. The PTB has been successful in providing price protection to customers and fostering switches. The PTB also included a rate reduction of 6% for residential and small commercial customers when competition began, so that even customers who did not switch suppliers received immediate benefits. The estimated rates under a regulated environment that are presented in response to Question 1 support the conclusion that customers have achieved rates that were better than regulated rates, whether they switched or remained with the PTB.

The broad trend that Ms. Biedrzycki's hand-out shows is that the PTB and Provider of Last Resort rates have increased to a greater degree than the rates of most of the electric cooperatives and municipally-owned utilities in Texas or the rates of electric utilities in other parts of the country. The utilities in Texas depend on natural gas for producing electricity, and some are more dependent on it than others. Since the initial fuel rates for the PTB were established in late 2001, the price of natural gas has more than tripled. Utilities that had significant ownership of coal and nuclear generation were able to minimize the increases in their electric rates. Nevertheless, the rates for most of the utilities in Texas and electric rates in other states have risen as a consequence of higher gas prices, and some of them have risen more than others.[10] In a regulated environment, the need for regulatory approval of fuel rate increases commonly has the result that increases in rates are delayed, but *reductions* in the rates are also delayed if fuel prices fall.

[10] For example, among the Texas utilities in the hand-out, an investor-owned utility, El Paso Electric Company had the smallest increase, 2%, and a cooperative, Magic Valley Electric Cooperative, had the largest, 153%.

While the information that Ms. Biedrzycki provided at the hearing of the Regulated Industries Committee was mostly correct, the rates are not a good proxy for the rates that would have been in effect in ERCOT had the utilities remained subject to rate regulation.[11] In her table 3, she showed changes in rates for regulated utilities, electric cooperatives and municipally-owned utilities. There are a number of reasons why the rates for different utilities would change at different rates and different times:

- Different utilities had different rates when retail competition began.
- Each of these utilities has made different arrangements for its long-term supply of power. For example, a number of these utilities have significant coal or nuclear generating capacity that has served to insulate them from increases in gas prices.
- The regulated investor-owned utilities operated under special circumstances after the enactment of Senate Bill 7 that limited their ability to change base rates. All of the investor-owned utilities except El Paso Electric Company were on the path to the introduction of retail competition and were subject to a statutory rate freeze until the PUC took action to delay competition. Even when competition was delayed for Entergy Gulf States, its rate freeze remained in effect initially under PUC order and now under legislation.
- El Paso Electric Company was under a ten-year rate freeze, as a part of its bankruptcy settlement, and it agreed to an extension of the freeze at about the time the original freeze expired.
- Utilities might be affected by significant growth in their service area that would require investment in new facilities.
- Utilities might be affected by the expiration of contracts to purchase power and might need to negotiate new contracts in a market that was more or less favorable than when the original contract was entered.
- The rules for the recovery of fuel costs for investor-owned utilities permit them to defer their costs, so that the recovery of cost increases is delayed and spread over a longer period.

[11] The only item that should be corrected appears in Ms. Biedrzycki's table 1, where she shows a December PTB rate for Centrica CPL of 17.70 cents/kWh and in Table 2 an increase of 99% for this REP. It appears that she transposed digits for the rate, and that the rate should have been 17.07, an increase of 92%.

Appendix 1--Specific Assumptions for Estimating Regulated Rate

Estimate of Regulated Cost of Service for TXU

1. Operating expenses are based on amounts reported by TXU in its PURA § 39.257 Annual Report for the year 2000.[12] Operations and maintenance expenses are assumed to be TXU's 2000 total operations and maintenance expense (as reported on Schedule III-A of its 2000 Annual Report) reduced by expenses associated with Alcoa's portion of the Sandow Unit, fuel and purchased power expenses, and expenses not allowed for ratemaking purposes pursuant to PURA § 36.062.

2. Capital structure and costs are based on TXU's actual capital structure and capital costs as reported in the 2000 Annual Report, except for the cost of equity, which is based on the national average for costs of equity authorized by state commissions during the year 2000.

3. Environmental costs of $400 million are amortized into cost of service to reflect expenditures related to emissions-reduction requirements of Senate Bill 7.

4. An estimated amount of $1.2 billion is amortized into the cost of service to reflect the remand of certain Comanche Peak costs originally requested in Docket No. 9300. (In June 2000, TXU filed its remand case in Docket No. 22652 requesting recovery of these costs, but subsequently dropped its request as part of its true-up settlement.)

5. Monthly fuel efficiency reports for 2000 and 2001 were used to develop base year data. The base year data included the total generation, total sales, and average price in $/MMBtu and $/MWh.

6. Coal and lignite price adjustments for both utilities were assumed to be the percentage change in the average price of coal delivered to utilities in Texas as compiled from DOE Form 423 for the years 2001-2005. More specific information for TXU and Reliant-HL&P was not available.

7. The natural gas price for gas delivered to the TXU generation sources was assumed to be the price at the Waha Hub, adjusted by the percentage change of the weighted average cost of gas at the Waha Hub from the prior year. Natural Gas Week was the source of the weighted average annual gas cost data.

8. The cost of nuclear fuel was considered stable during the 2001-2005 periods and did not change from the base year amounts.

9. Demand that could not be met from the existing TXU generating fleet came from purchases from an independent generator. This hypothetical acquisition was based on the actual demand and energy requirements of TXU Electric Delivery customers. Required capacity includes a reserve margin equal to 12% above actual firm peak demand.

10. All-in costs and heat rate for a combustion turbine were used for purposes of determining purchased capacity and energy costs. The following costs were used:

[12] Per the terms of its true-up settlement in Docket No. 25230, TXU did not file an Annual Report for the year 2001.

construction cost: $395/kW; annual revenue requirement: $67.27/kW; fixed O&M cost: $10.72/kW; variable O&M cost: $.000316/kWh; heat rate: 10,817 Btu/kWh.

11. The Functional Revenue Requirements were allocated to the Residential Class using a Residential Allocator that was derived from data from the pre-UCOS rate cases (Docket No. 18490 for TXU).

12. The annual number of bills was calculated by multiplying FERC Form 1 information by 12.

13. A weather-normalized Annual kWh was estimated by averaging FERC Form 1 data (for TXU averaged 1998-2000, for CNP averaged 1998-2001).

14. The Retail Transmission Cost of Service was allocated to Residential Customer Class using the 4CP Allocator, consistent with the UCOS cases.

15. Cost and consumption information was used to generate a hypothetical bill, assuming 1000 kWh.

16. The combined Purchased Power data and Fuel Factor data were added to the Total Base Rate in the hypothetical bill, and the total on the bill was divided by 1000 kWh to derive a cents per kWh for the Total of the Base Rate, Fuel Factor, and Purchased Power.

17. Different rates were calculated for each year to 2005, as the Fuel and Purchased Power requirements and costs changed yearly.

Estimate of Regulated Cost of Service for CenterPoint Energy

1. Operating expenses are based on amounts reported by CenterPoint in its PURA § 39.257 Annual Report for the year 2001. Operations and maintenance expenses are assumed to be CenterPoint's 2001 total operations and maintenance expense (as reported on Schedule III-A of its 2001 Annual Report) reduced by fuel and purchased power expenses and expenses not allowed for ratemaking purposes pursuant to PURA § 36.062.

2. Capital structure and costs are based on CenterPoint's actual capital structure and capital costs as reported in the 2001 Annual Report, except for the cost of equity, which is based on the national average for costs of equity authorized by state commissions during the year 2001.

3. Environmental costs of $382 million[13] are amortized into cost of service to reflect expenditures related to emissions-reduction requirements of Senate Bill 7.

4. Monthly fuel efficiency reports for 2000 and 2001 were used to develop base year data. The base year data included the total generation, total sales, and average price in $/MMBtu and $/MWh.

5. Coal and lignite price adjustments for both utilities were assumed to be the percentage change in the average price of coal delivered to utilities in Texas as

[13] Of the $718 million of environmental expenditures approved in CenterPoint's true-up case, approximately $336 million was reflected in the 2001 Annual Report. The estimated regulated revenue requirement assumes that the difference of $382 million is also reflected in regulated rates.

compiled from DOE Form 423 for the years 2001-2005. More specific information for TXU and Reliant-HL&P was not available.

6. The natural gas price for gas delivered to the CenterPoint generation sources was assumed to be the Katy Hub, adjusted by the percentage change of the weighted average cost of gas at the Katy Hub from the prior year. Natural Gas Week was the source of the weighted average annual gas cost data.

7. The cost of nuclear fuel was considered stable during the 2001-2005 periods and did not change from the base year amounts.

8. Demand that could not be met from the existing CenterPoint generating fleet came from purchases from an independent generator. This hypothetical acquisition was based on the actual demand and energy requirements of CenterPoint customers. Required capacity includes a reserve margin equal to 12% above actual firm peak demand.

9. All-in costs and heat rate for a combustion turbine were used for purposes of determining purchased capacity and energy costs. The following costs were used: construction cost: $395/kW; annual revenue requirement: $67.27/kW; fixed O&M cost: $10.72/kW; variable O&M cost: $.000316/kWh; heat rate: 10,817 Btu/kWh.

10. The Total Revenue Requirement was allocated using a Total Revenue Allocator derived from the total revenue allocation in the UCOS cases.

11. The Functional Revenue Requirements were allocated to the Residential Class using a Residential Allocator that was derived from data from the pre-UCOS rate cases (Docket No. 12065 for CenterPoint).

12. The annual number of bills was calculated by multiplying FERC Form 1 information by 12.

13. A weather-normalized Annual kWh was estimated by averaging FERC Form 1 data (for TXU averaged 1998-2000, for CNP averaged 1998-2001).

14. The Retail Transmission Cost of Service was allocated to Residential Customer Class using the 4CP Allocator, consistent with the UCOS cases.

15. Cost and consumption information was used to generate a hypothetical bill, assuming 1000 kWh.

16. The combined Purchased Power data and Fuel Factor data were added to the Total Base Rate in the hypothetical bill, and the total on the bill was divided by 1000 kWh to derive a cents per kWh for the Total of the Base Rate, Fuel Factor, and Purchased Power.

17. Different rates were calculated for each year to 2005, as the Fuel and Purchased Power requirements and costs changed yearly.