ANALYSIS ON VARIOUS PRICING SCENARIOS IN A DEREGULATED ELECTRICITY MARKET

A Thesis

by

CATALINA AFANADOR DELGADO

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2006

Major Subject: Mechanical Engineering

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Approved by:

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ABSTRACT

Analysis on Various Pricing Scenarios in a Deregulated Electricity Market.

(August 2006)

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Chair of Advisory Committee: Dr. W.D. Turner

The electricity pricing structure in Texas has changed after deregulation (January 2002). The Energy Systems Laboratory has served as a technical consultant on electricity purchases to several universities in the Texas A&M University System since 2001. In the fiscal year of 2006 Stephen F. Austin State University joined with the TAMU campuses and agencies, and there are now 183 accounts in the Electric Reliability Council of Texas (ERCOT) North, Northeast, South, West, and Houston areas of Texas. From the 183 accounts, 9 Interval Data Recorder (IDR) accounts consume 92% of the total load. The objective of this research is to find the most economic price structure to purchase electricity for the Texas A&M System and Stephen F. Austin University by analyzing various pricing scenarios: the spot market, forward contracts, take or pay contracts and on/off season (tiered) contracts. The analysis was based on the 9 IDR accounts. The prices for the spot market were given by ERCOT and the other prices by Sempra. The energy charges were calculated every 15 minute using the real historical consumption of each facility and the aggregated load of all facilities. The result for the analysis was given for each institution separately, as well as for the

aggregated load of all facilities. The results of the analysis showed that the tiered price was the most economical structure to purchase electricity for each individual university and for the total aggregated load of all 9 IDR accounts. From March 1, 2005 to February 28, 2006, purchasing electricity on the tiered price would have cost $13,810,560. The forward contract, that is, purchasing electricity on a fixed rate, was the next cheapest with an energy cost of $14,266,870 from March 1, 2005 to February 28, 2006, 3% higher than purchasing electricity at the tiered price.   The most expensive method to purchase electricity would have been the spot market. Its energy costs would have been approximately $18,171,610, 36% and 31% higher, respectively, than purchasing electricity at the tiered price and the fixed rate.

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CHAPTER I

INTRODUCTION

A. Basis for the Thesis

Electric utility deregulation began in Texas on January 1, 2002. The Energy Systems Laboratory worked with several universities in the TAMUS, aggregating their electric loads and procuring their electricity through a single contract, the first signed in November 2001 to be effective January 1, 2002. Since that initial contract, several purchases have been made, including a purchase in July 2005 for the 2005-2006 academic year. At that contract negotiation, several pricing scenarios were obtained from the electricity providers, and this thesis will provide a detailed analysis of the options available to the Chief Financial Officers in their decision-making process. The thesis will also discuss the rationale behind the pricing scenarios in a deregulated environment and the methodologies used in the analysis. Two analyses will be performed; one from March 1 to August 31, 2005, and another one from September 1, 2005 to February 28, 2006.

It is appropriate, however, before discussing the TAMUS electricity purchases, to provide a brief history of electricity deregulation in the United States. Three models will be presented in some detail; California deregulation; the PJM (Pennsylvania - New Jersey - Maryland) experience; and the Texas deregulation approach.

This thesis follows the style of the Journal of Industry, Competition and Trade.

B. History of Electric Utility Deregulation

In the early 90's, the electricity industry was monopolized by investor-owned utilities, municipal utilities and cooperatives and prices were regulated. Consumers had no choice but to purchase electricity from the local utility at the regulated price. The success of deregulation of other products such as natural gas, motivated many states to start the deregulation of electricity. The first state to deregulate electricity was California and 18 states (including District of Columbia) followed (EIA , 2003a). Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas and Virginia are states with an open competitive electricity market (EIA , 2003a). After much discussion, Alabama (APSC, 2000), Arkansas (APSC, 2003), Colorado (PUCC, 1999), Idaho (IPUC, 1996), Kentucky (KPSC, 2005), New Mexico (NMPRC, 2005), Nevada (EIA , 2003a), Oklahoma (EIA , 2003a), and South Carolina (PSCSC, 1998) decided to keep their regulated electricity structure. Montana (PSCM, 2006) is working on having an open competitive electricity market in the future and Georgia (GPSC, 1996) does not have a deregulated electricity market, although customers with a demand of at least 900 kW can choose their electricity supplier one time (GPSC, 2006). Alaska (RCA, 2006), Florida (FPSC, 2006), Hawaii (EIA, 2003a), Indiana (IURC, 2006), Iowa (IUB, 2006), Kansas (KCC, 2003), Louisiana (LPSC, 2006), Minnesota (MPUC, 2006), Mississippi (MPSC, 2006), Missouri (MPSC, 2005), Nebraska (NPA, 2006), North Carolina (NCUC, 2006), North Dakota (NDPSC, 2006), South Dakota (SDPUC,2005), Tennessee (TRA, 2006), Utah

(PSCU, 2006), Vermont (VPSB, 2006), Washington (WUTC, 2006), West Virginia (PSCWV, 2006), Wisconsin (PSCW, 2006), and Wyoming (EIA, 2003a) have a regulated electricity structure. California as a result of problems encountered with deregulation, changed their utility structure and does not have an open competitive electricity market. The electricity rates are regulated (CPUC, 2001). See Figure 1 for the status of the electricity market in the US in 2006.

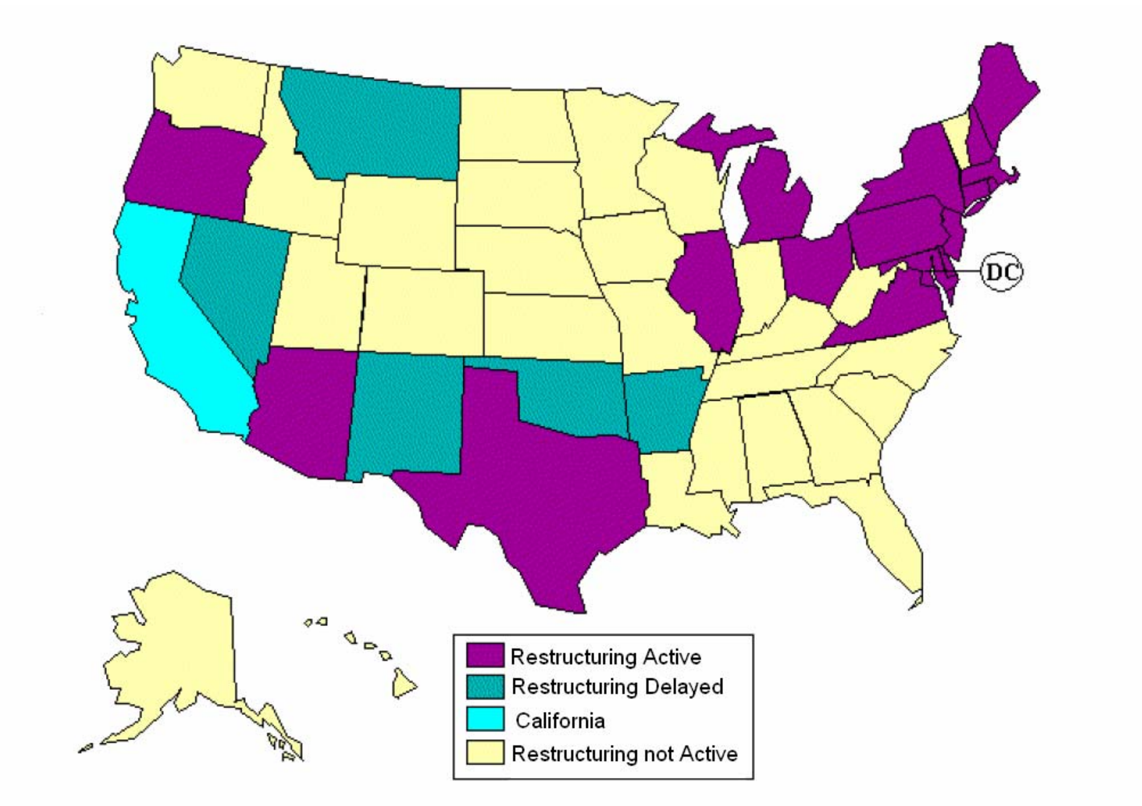

Figure 1. Status of Electricity Market for Each State (EIA, 2003a)

1. California Deregulation

California was the first state in the US to deregulate electricity and gave a good example of what not to do to other states. Prior to deregulation, all electricity was sold by private, investor-owned utilities, municipal utilities and cooperatives. These utilities were in charge of power generation, delivery and metering services. The high electricity prices led California to deregulate the electricity market. High electricity prices were caused by different events. First, electricity prices were affected by PURPA (Public Utility Regulatory Policies Act of 1978). PURPA was created as a response to the oil crisis of the 70's, and it encouraged a more efficient power industry while benefiting the environment. It created the qualifying facilities (QFs), which were small facilities that could generate power with wind, solar, biomass or geothermal energies (Carl Blumstein, et al., 2002). It also increased cogeneration and motivated energy conservation. Utilities were obliged to purchase the excess amount of electricity generated by QFs in order to reduce emissions and eliminate dependency on other sources of energy such as oil (Carl Blumstein, et al., 2002). The price at which electricity was bought from QFs was usually high due to technology and as a motivation to produce green power energy. Utilities in California signed long term contracts as long as 20 to 30 years with rates that increased exponentially from 5 cents per kWh to 12 cents per kWh (Carl Blumstein, et al., 2002), based on high oil prices over the following decades. By 1985, more than 15,000 MW of power generated by QFs was being sold to Californian Utilities. In 1991, 26.2% of electricity delivered to California was produced by QFs (Carl Blumstein, et al., 2002).

The power industry in California was also affected by the lack of projects to construct new power generation; approximately 7,000 MW came on line in a period of eight years prior to 1991. Most of this new capacity was due to completion of nuclear power plants started in the 1970's, whose construction had been slowed by regulatory and safety issues. There was no motivation by California's Public Utility Commission for construction of new power plants (Carl Blumstein, et al., 2002). As a matter of fact California imported electricity to the State. In 1991, the electricity rate in California varied from 9 to 10.5 cents per kWh, 30 to 50% higher than electricity rates in other parts of the US (Carl Blumstein, et al., 2002).

Under the deregulation process, an Independent System Operator (ISO) was created (Carl Blumstein, et al., 2002). The ISO was in charge of ensuring an open and nondiscriminatory transmission access to all competing generators and to balance the electricity demand and supply. An electricity market, called the Power Exchange Market, was created to control all electricity sold and bought on the spot market. The Power Exchange Market was a day ahead spot market with bids taking place at 6 am, midday and 4 pm. No long-term contracts could be signed, and all electricity had to be bought on the Power Exchange Market. The ISO was in charge of scheduling the delivery of electricity bought on the Power Exchange Market and providing additional electricity when supply was short to meet demand (Carl Blumstein, et al., 2002).

At the time of deregulation, there were three investor-owned utilities, Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric. All three utilities were mandated to divest at least fifty percent of their power generation capacity, and in fact, they all sold their fossil-fueled generation. Recovery of stranded costs was to be achieved by charging the Competitive Transition Charge approved by the California Public Utilities Commission (CPUC). All stranded costs were estimated to be recovered by 2005. The stranded costs are the facilities investments built by the utility over the years in order to meet the demand. In a regulated environment, these costs are included in the rate base; however, they would not be able to recover them in an open competitive market. Deregulation started in California on January 1st, 1998, and the electricity rate was decreased by 10% and frozen for a period of four years (Carl Blumstein, et al., 2002). This was done in order for customers to see immediate deregulation benefits and make it popular.

In supplying electricity, it is important that transmission lines are maintained within its thermal limits. If one transmission line is over loaded, it will cause the whole system to shut down. Therefore, not only it is important to have the adequate balance between supply and demand but also to stay in the operational limits of the power lines. It is crucial to recall that even if there is enough power to meet demand, the transmission lines must be adequate to distribute the power to the source without overheating. The Californian ISO was responsible for solving problems that could arise due to transmission congestion.

The power generators bid their electricity in the Power Exchange Market and reported their power generation "location" for each hour of the day. Scheduled Entities then scheduled the amount of electricity needed and the delivery location. Power generators also provided information on bids to the ISO if extra electricity was needed. All this information was sent to the ISO to determine congestion zones in order to adjust bids and resolve congestion problems (Carl Blumstein, et al., 2002). For example, if too much power was scheduled to be transferred from North to South, then the generators in the North were ordered to reduce the power being delivered to the South and South generators were ordered to increase their load, thus reducing the load in the transmission lines from North to South. The power exchange had an opportunity to change the schedule to correct the congestion problem, although it never did, and the ISO had to call for bids to correct the congestion on the transmission lines. In theory, all power should be bought on the day-ahead market of the power exchange market, and all other necessary power to solve transmission congestion or short supply would be bought on the real time market of the ISO. This created a problem since in reality most power generators bid most of their power generation in the ISO to obtain the high prices of the real-time market (Carl Blumstein, et al., 2002).

The ISO was also responsible for spinning reserves and non- spinning reserves. The spinning reserves are the capacity to provide power in case of a shortage in power supply due to a failure in the system. The spinning reserves are usually supplied by generators that operate at less than maximum capacity and could increase their load immediately if the system requires it. The non-spinning reserves are the capacity to provide more electricity if needed, however, the electricity to be provided is not synchronized to the system and will take a specified time to put it on the system. It is also the amount of electricity that can be removed from the system, if necessary, at a specified time.

The prices to bid both in the ISO and in the Power Exchange Market had a capped price of $250 per MWh, which tripled over time (Carl Blumstein, et al., 2002). Small customers could see an immediate benefit by decreasing their electricity rate by 10%. Bonds were used to make this price reduction possible. However, the bonds were not sufficient to cover the 10% reduction in the electricity rate and a non-bypassable charge was approved until the bonds were paid. The retail rates paid by end-use customers were considered to be higher than the combined costs of the electricity price on the Power Exchange Market, and transmission and distribution charges due to the Competitive Transition Charge. The Competitive Transition Charge was effective until stranded costs were recovered. Nevertheless the Competitive Transition Charge would expire by April 1st, 2002 even if stranded costs had not been recovered (Carl Blumstein, et al., 2002). After the frozen period, electricity rates for electricity providers would depend on the average of electricity price of the spot market. Large customers had their electricity rates frozen. Large customers were considered those who received power from transmission lines with 50 kV or greater.

The competition for new electric providers was tough. Customers could choose their electric provider or stay with the one they had; however, few customers switched providers. Electric providers could only compete if they could sell electricity for less than the electricity price on the spot market or if their competition had actually bought electricity at a higher price compared to the spot market.

There were several factors that affected deregulation in California. The first factor was the impediment to sign long-term contracts. There was no incentive for power generators to make their production more efficient and cheaper since all their electricity would be sold on the Power Exchange Market at any given price. The retail utilities had to provide electricity at a fixed price and it was too low compared to the prices paid on the Power Exchange Market, and they were losing money.

The second factor was having more demand than supply within California. California is an importer of electricity (Nabors, et al., 2002), and has had little growth in power generation. What made it even worse was the reduction in imports in 2000 and 2001 due to dry climate conditions from their exporters in the Pacific Northwest Region. The third factor was the assumption of low electricity prices in the Exchange Power Market. Wholesale prices were higher than estimated which made it impossible to recover stranded costs by April 1st, 2002 for some retail companies. However, San Diego's Utility recovered stranded costs in 2000 and was allowed to change their frozen rate. At this time, customers started seeing the effects of high prices in their electricity bills (Carl Blumstein, et al., 2002). See Table 1 for wholesale electricity prices.

Table 1. Wholesale Electricity Price in California ($/MWh) (Carl Blumstein, et al., 2002)

	1998 ($/MWh)	**1999 ($/MWh)**	**2000 ($/MWh)**	**2001 ($/MWh)**
April	23.3	24.7	27.4	265.9
May	12.5	24.7	50.4	239.5
June	13.3	25.8	132.4	159.8
July	35.6	31.5	115.3	137.8
August	43.4	34.7	175.2	120.1
September	37.0	35.2	119.6	126.8
October	27.3	49.0	103.2	69.4
November	26.5	38.3	179.4	74.8
December	30.0	30.2	385.6	69.6
January	21.6	31.8	272.0	
February	19.6	18.8	304.4	
March	24.0	29.3	249.0	
Mean	26.2	31.2	176.2	

There are several causes for the high electricity prices in the Power Exchange market. First as mentioned above was the reduction in electricity imports (Carl Blumstein, et al., 2002). Second, most of California's power plants are fueled with Natural gas (EIA, 2006). See Figure 2 for percentages of different type of fuels used in power generation in California.

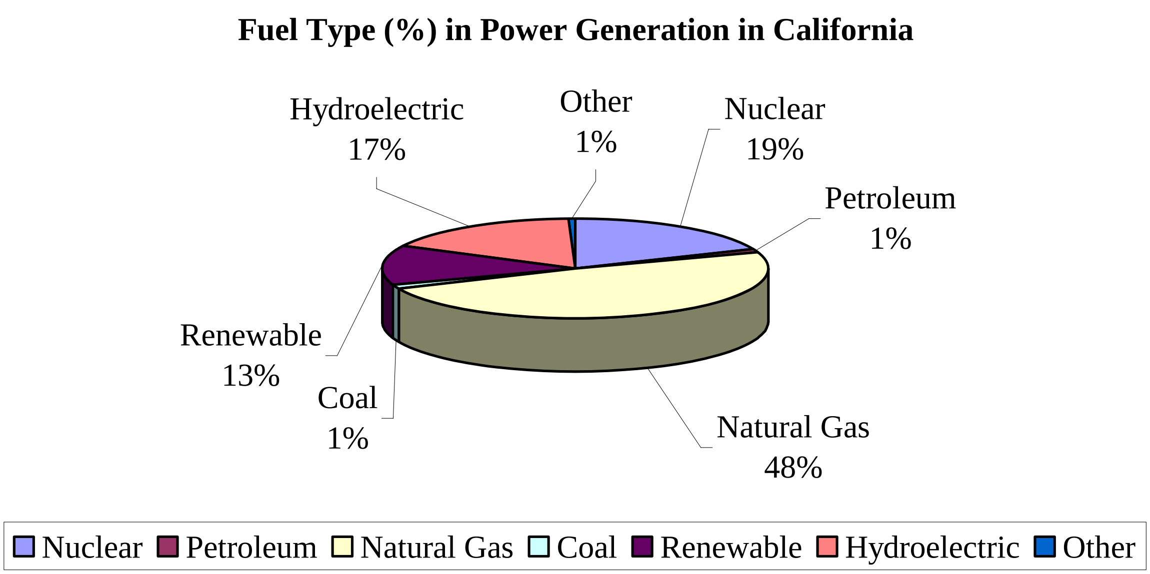

Figure 2. Fuel Type Percentage in Power Generation in California (EIA, 2003b)

Electricity prices in deregulated states are directly affected by the costs of their fuel. See Figure 3 for the types of fuel used in each state (EIA, 2000). After being stable for several years, natural gas prices started increasing in 2000, and reached peaks nearly three times the long-term average price.

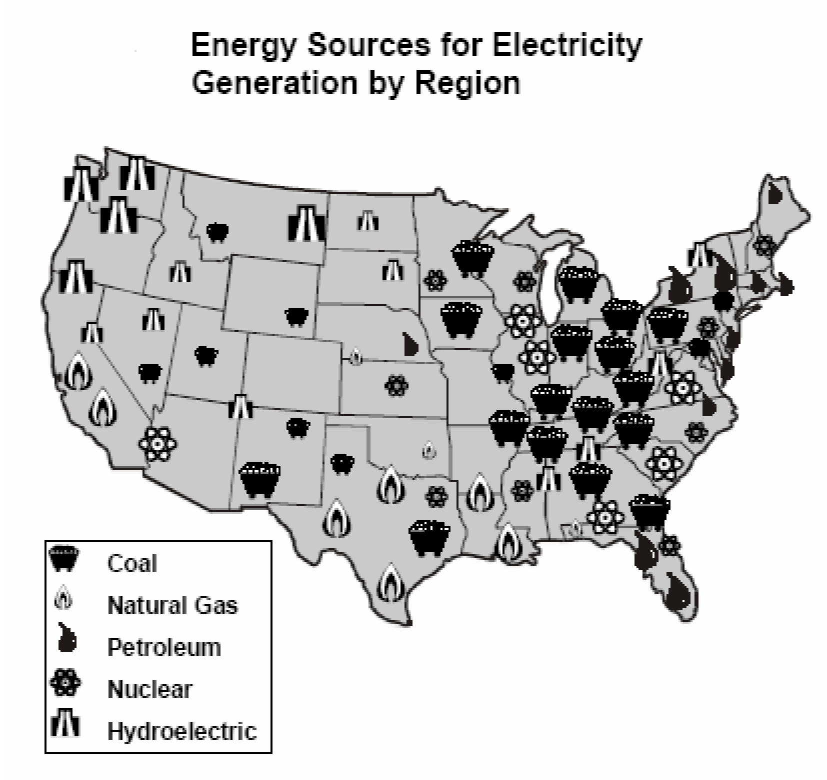

Figure 3. Fuels Used in Power Generation in Each State (EIA, 2000)

For example, natural gas prices in California in January 2000 were approximately $2 per MMBTU, in June, $4 per MMBTU and by September, $6 per MMBTU (Carl Blumstein, et al., 2002). The third reason for the California pricing problems involved the prices for mandatory permits of emissions of power plants. These increased by a factor of 10 by April 2000. The fourth factor was the market power executed by power generators during peak times (Carl Blumstein, et al., 2002).

The new power generators had no interest in having a low electricity price since they did not have to recover stranded costs, like the retail providers did. Generators played with the amount of electricity they offered to sell. They were aware that withholding even a small capacity would affect the balance between supply and demand, generating higher electricity prices in the Power Exchange Market and therefore greater profits for the power generator utilities. This method is called market power. Power generation utilities would decrease their load production, arguing restriction on their nitrogen oxide emissions or failures in their power plants. However, it has been argued that this was just a strategy to increase electricity prices.

Table 2 shows the number of hours of power curtailment in 2001 and 2002 was more than 3 times the number of hours of power curtailment in 1999 and the beginning of 2000.

Table 2. Power Curtailment (MW off Line) in California for Different Years (Carl Blumstein, et al., 2002)

	Average Daily Schedule MW Off Line			
Month	**1999**	**2000**	**2001**	**2002**
January	3,069	2,423	9,940	11,166
February	5,096	3,243	10,895	12,702
March	5,740	3,389	13,737	12,753
April	5,739	3,329	14,911	11,385
May	3,032	4,012	13,413	
June	1,216	2,683	6,758	
July	963	2,233	5,044	
August	878	2,434	4,229	
September	1,195	3,621	5,278	
October	1,761	7,633	8,805	
November	2,988	10,343	12,199	
December	2,569	8,988	11,112	

The amount of outages in California from November 2000 to May 2001 was significantly higher than previous years. Table 3 indicates the peak demand at which the power was curtailed in California (Carl Blumstein, et al., 2002)

Table 3. Curtailment Date and Corresponding Peak Demand (Carl Blumstein, et al., 2002)

Date	Day	Peak Demand (MW)	Number Hours Curtailed
6/14/2000	Wednesday	44,239	NA
1/17/2001	Wednesday	29,727	3
1/18/2001	Thursday	29,537	3
1/21/2001	Sunday	27,657	1
3/19/2001	Monday	29,476	6
3/20/2001	Tuesday	29,691	6
5/7/2001	Monday	33,446	2
5/8/2001	Tuesday	34,455	2

At the same time, eight blackouts occurred between spring 2000 and 2001 even though the demand levels were below the summer's peak demand. California's load capacity is estimated to be around 44,000 MW with a peak demand of approximately 45,000 MW (Joskow, 2001). When blackouts occurred, except for June 2000, they were all within the load capacity of California. Even the peak demand during 2000 was 44,239 MW, lower than the peak demand of 1999, 45,574 MW, which did not generate a blackout. Although imports to California were reduced, the peak demands at which curtailment occurred, for 7 out of 8 blackouts, were significantly below the capacity of California (44,000 MW), which has led to the discussion that blackouts in California happened due to transmission constraint and not the lack of electricity supply. Blackouts led to million of dollars lost by different companies. For example, California Steel Industries, Inc. reported millions of dollars lost due to the blackouts (Zellner, et al., 2001).

Increases in wholesale prices of electricity and blackouts were also caused by the market manipulation created by electricity brokers such as ENRON. Electricity brokers operated as intermediaries that looked for surpluses of energy to be sold in other locations lacking electricity. ENRON was considered to be one of the most highly respected companies in the US and had been recognized by several institutions for its projection into the future and its increasing valuable stock (Kulik, 2005). However, Electricity providers such as ENRON used methods such as “Get Shorty”, “Megawatt Laundering” and “Death Star” to increase their profits (Zellner, et al., 2001).

All of the above were easy to do since in reality one kWh cannot be traced to see who is using it or where it is going or who delivered it. The electricity bought on the power exchange market had a capped price that could not be exceeded; however, electricity coming outside of California could be sold with prices exceeding the capped price. In “Death Star”, ENRON scheduled power that never existed, and would use this to sell power at a higher price to solve the congestion on the transmission lines. Subsequently, companies like ENRON would buy electricity in California, send it to other states, and then bring it back to California and sell it at a higher price, also known as “Megawatt Laundering”. “Get Shorty” was used by ENRON and other companies to sell products that most likely will not have to provide, such as reserve capacity, or which would be able to purchase at a lower price. (Clarke, 2005)

Utility providers lacking future contracts could not hedge their risk. Call options, which would pay the additional amount of money if the electricity price were to increase, could not be bought. In the spring 2000, the electricity market started to fall apart in California. Electricity prices on the Power Exchange market started to increase by as much as 500%. The electricity prices at the beginning of 2001 were almost 10 times the prices of 1998 and 1999, see Table 1 (Carl Blumstein, et al., 2002). Retail providers were paying a very high electricity price on the Power Exchange Market and were selling it for less.

SCE and PG&E were in bankruptcy and stopped making payments to the Power Exchange Market. The power exchange market collapsed and the California Department of Water Resources started purchasing electricity from the utility generators in order to provide electricity to end-use customers (Carl Blumstein, et al., 2002). This time long term contracts were permitted. In 2001 new power generation came on line in California and by June 2001 electricity prices began to decrease. The State forbade direct access to customers in 2001 (CPUC, 2001) and in 2003, the California Department of Water Resources started the transition for retail utilities to resume purchasing electricity from power generators (CPUC, 2004).

2. Pennsylvania, New Jersey and Maryland Deregulation

Not all deregulation processes have been chaotic; the Pennsylvania, New Jersey and Maryland (PJM) deregulation has a different story from the one in California. There are many facts that helped with the success of deregulation in this region. First, this region is an exporter of electricity, which helps avoid a shortage in the electricity supply. As a matter of fact, the region under the PJM ISO is the second largest producer of electricity and the largest electricity grid in the US (Frank J. Richards, 2002). The PJM ISO controls 59,000 MW and supplies energy to more than 22 million customers. It has a recorded peak demand of 52,200 MW (July 23rd, 2001) (Frank J. Richards, 2002).

Secondly, this region does not have the environmental restriction that California faces, leading to accessible permits of emission of gases produced by power plants, causing a continuous addition of power plants, and resulting in 35% excess capacity of electricity in the region. The third factor is the type of fuel used in power generation. Ninety percent (90%) of power plants are fueled with coal and nuclear energy; therefore the increase in natural gas price did not affect the electricity price in Pennsylvania like it did in California. See Figure 4 for fuel percentages used in power generation in Pennsylvania.

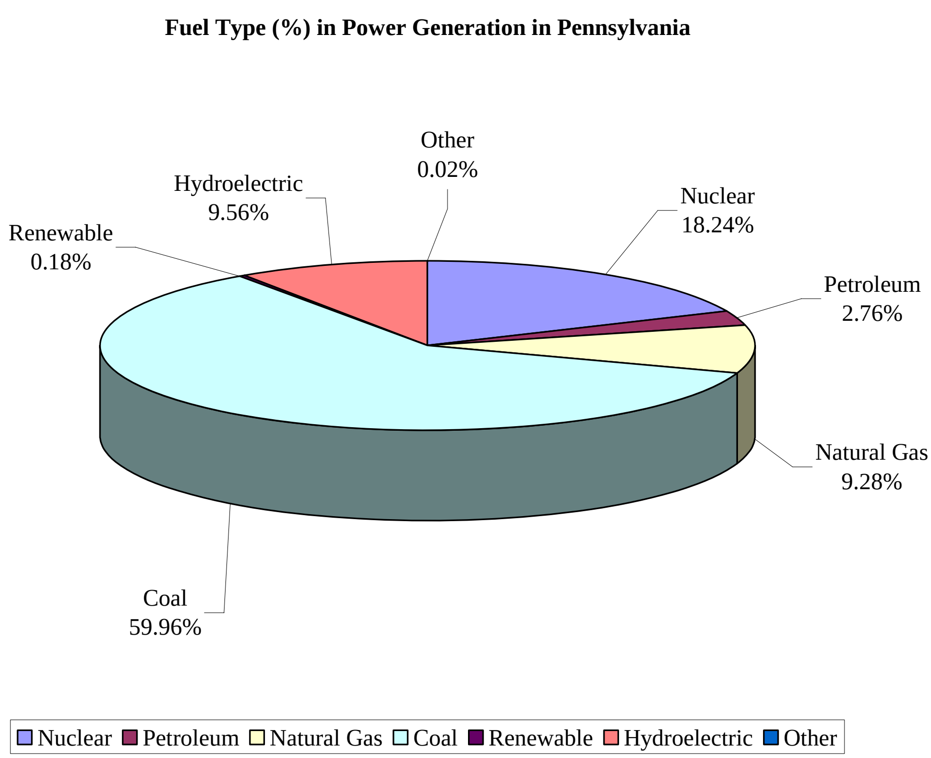

Figure 4. Fuel Type Percentage in Power Generation in Pennsylvania (EIA, 2003c)

Deregulation was signed in December 1996 by Governor Tom Ridge and started in January 1999. There were no restrictions related to the contracts between power generator and electricity providers (Frank J. Richards, 2002). Long-term contracts were not forbidden as it was in California. With deregulation, divestiture of power generation, distribution and transmission was not mandatory; however, the separation of services was obligatory. Most of the electric providers divested their power generation and recovered some part of stranded costs. The PJM ISO was given the responsibility to guarantee open and nondiscriminatory access to transmission lines for all electricity providers. The PJM ISO was also responsible, up to this day, for operating a real time market for electricity. Similar to Texas, transmission and distribution were not deregulated.

Deregulation in the PJM zone mandated a rate reduction in electricity prices, which had to be offered for 54 months or until all stranded costs were recovered, whichever came first (Frank J. Richards, 2002). However, electricity prices offered by incumbent electricity providers remained high, due to the transition charge, stimulating new electricity providers to come into the deregulated market.

There was one problem in this process, customers who were under new electric providers, were offered a lower electricity rate in the fall and winter, but a higher rate in the summer. They would then return to their affiliated electric provider in the summer for a lower electricity price (Frank J. Richards, 2002). In 2000, the public utility commission increased the energy charge of the affiliated electric providers in order to avoid customers switching back and forth during the summer. If a customer switched back to its affiliated electric provider, they would actually pay the wholesale price rather than the regulated price. Wholesale prices tended to be higher than the regulated prices during the summer (Electric World, 2001).

In April 2001, there were around 130 electric providers in Pennsylvania. Overall electricity prices had fallen 20 % and there were more options available to the customers such as green power (Frank J. Richards, 2002). Concurrently, deregulation provided benefits to the environment. Green power producers had won 20% of customers after deregulation, creating 36,000 new jobs by 2004.

3. Texas Deregulation

The 1999 Texas Choice Act (known as Senate Bill 7) passed by the Texas legislature made deregulation of electricity pricing possible in Texas (PUCT, 1999). Senate Bill 7 mandated that all investor-owned utilities participate in deregulation. Municipal utilities and cooperatives had the option to choose whether or not they participated. Prior to deregulation a utility produced, metered and distributed energy to end-use customers. There was only one affiliated utility serving one geographical area and customers had no choice in selecting their utility provider.

On January 1st, 2002 deregulation of electricity pricing began in Texas in the region covered by ERCOT (Electric Reliability Counsel of Texas). ERCOT covers approximately 75% of the State (El Paso Region, the northern panhandle, a small area around both Texarkana and Beaumont are not included in ERCOT). It is divided into five regions: North, South, West, Northeast, and Houston. See Figure 5 . ERCOT monitors 85% of the state’s electric load. In the area covered by ERCOT, there are over 500 generating units with a total capacity of approximately 77,000 MW and 38,000 miles of transmission lines (ERCOT, 2005a). The highest peak demand recorded in ERCOT's area is 60,270 MW on August 2005, followed by a peak demand of 60,095 MW on August 7th, 2003 (ERCOT, 2005a). The reserve margin, the amount of unused available capability of electric power at peak load, in ERCOT is 15-17%.

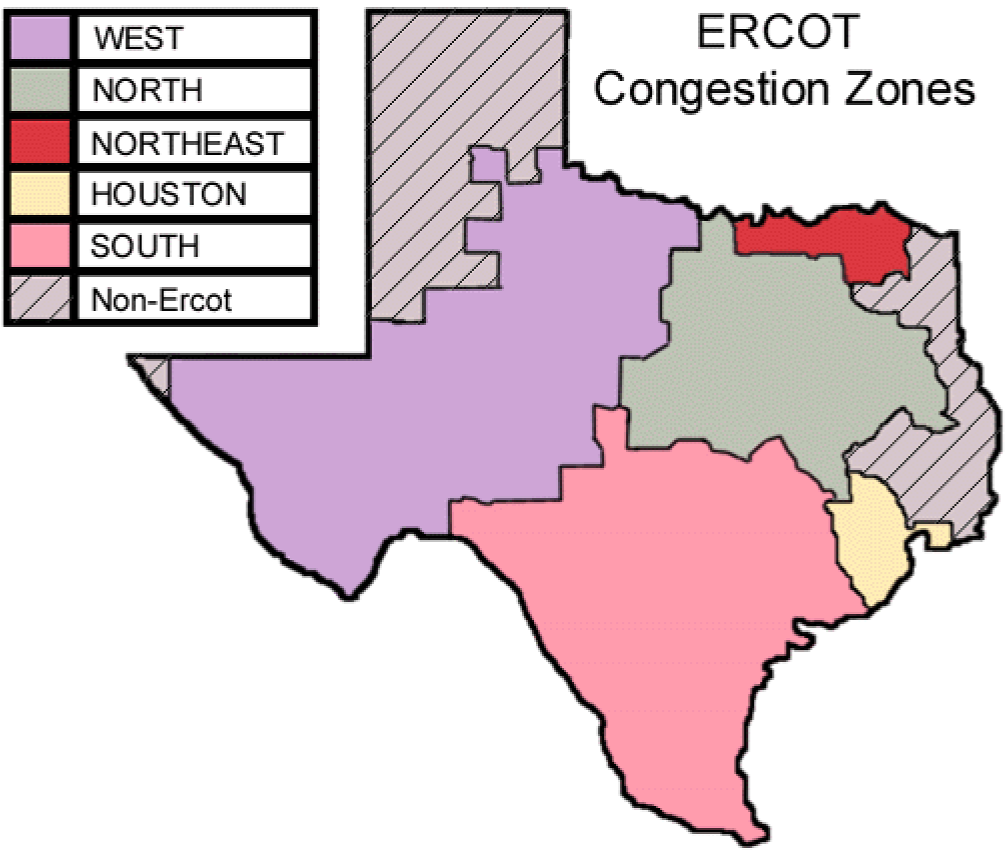

Figure 5. ERCOT's Zone Map (Ngr Stream Services)

Prior to deregulation ERCOT was only responsible for the electricity transmission reliability and for scheduling the power transfers between wholesale providers and end-use customers. Under Senate Bill 7, ERCOT responsibilities expanded, and generation, retail services, transmission and distribution were separated from each other (PUCT, 2005). Transmission and distribution were not deregulated. The transmission charge is only eligible for a nominal return on the investment so there is no market motivation to invest in it. The transmission system delivers electricity on power lines with a voltage higher or equal to 60 kV. It transfers electricity through power lines from high voltages to lower voltages (distribution system) and vice versa. The distribution system delivers electricity through power lines with a voltage lower than 60 kV, to end-use customers and wholesale customers.

Prior to deregulation, a freeze period from September 1, 1999 to January 1, 2002 was established. During this period, the electricity rates effective on September 1, 1999 were offered through January 1, 2002 when the price to beat went into effect (PUCT, 2000). This period gave the utilities the opportunity to recover stranded costs.

The recovery of stranded costs was to be analyzed two years after customer choice was introduced. The period of time in which transition charges could be applied could be extended and/or transition charges could increase depending on the recovery of stranded costs. At the same time, during the freeze period utilities could securitize 100% of their assets and up to 75% of the initial estimate of stranded costs. Stranded costs after January 1, 2002 could be recovered using either the sale of the generating utility's assets, stock evaluation methods, or exchanging assets (PUCT, 2000).

As a starting point to deregulation, on June 1, 2001 retail utilities offered a pilot program to five percent of their customers. In this program, end-use customers could choose their utility provider. The five percent of customers were chosen on a first come, first serve basis. On January 1, 2002 all utilities participating in deregulation offered their customers the price to beat (PTB) for sixty months. The price to beat was six percent lower than the energy charge offered on December 31, 2001, adjusted for fuel twice a year, and could only be offered to customers with a peak demand of 1000 kW or less (PUCT, 1999). The adjustment for fuel in the price to beat should be the same percentage of the change of fuel cost and should only be made if the fuel cost increased by at least ten percent. The price to beat would expire five years after January 1, 2002 or until the REP lost forty percent of the load served to the region.

There are over a hundred Retail Electric Providers (REP) in Texas (ERCOT, 2006a). A Retail Electric Provider does not generate electricity but it sells electricity to end-use customers over regulated transmission or distribution lines. Each REP had to offer the price to beat in their affiliated transmission and distribution territories for a period of thirty six months or until forty percent of its customers eligible for the price to beat had switched to non-affiliated REPs. If a retail electric provider delivered loads in excess of 300 MW, five percent of the load should be delivered to residential customers. A $1/MWh penalty should be paid for every MWh that was under the five percent requirement. This penalty is to be paid to the System Benefit Fund created under Senate Bill 7.

The System Benefit Fund was created in order to provide customer education, assistance to low-income customers and compensate schools for their losses due to restructuring of the electricity industry. Low-income customers are eligible for up to 20% discount in electricity bills (PUCT, 1999).

Power generation companies could not own and control more then twenty percent of the load capacity located in or able to be delivered to a power region. Each investor owned utility owning more than 400 MW had to auction at least fifteen percent of the utility's installed generation capacity for sixty months or until forty percent of the consumption of the load was served by a competitive REP (PUCT, 1999).

Senate Bill 7 applied environmental restrictions to grandfathered power plants. Grandfathered power plants did not require an air quality permit since they were built before the implementation of the Federal Clean Air Act, and had not made any major upgrades since September 1, 1971. Under Senate Bill 7 grandfathered power plants had to reduce the level of nitrogen oxides and sulphur dioxides emissions of 1997 by 50% and 25% respectively. Reducing the emissions of these gases is equivalent to removing 4,000,000 cars from Texas. By May 2003, the requirement of the reduction of the emission of theses gases was met (Frank J. Richards, 2002).

At the same time, restrictions were applied on nitrogen oxides and sulphur dioxides emissions on the East, West, and El Paso regions. The East Region of Texas could not have nitrogen oxides and sulphur dioxides emissions higher than 0.14 and 1.38 pounds per million British thermal units respectively, the West and El Paso Regions emissions of nitrogen oxides could not exceed 0.195 pounds per million British thermal units.

Another requirement of Senate Bill 7 was having 2000 MW (equivalent to serving 200,000 homes in Texas) of renewable energy in ERCOT's region by January 2009. Currently, there is around 2,000 MW of wind capacity, showing this mandate will be met prior to the deadline (ERCOT, 2006b).

ERCOT is one of the six Independent System Operators (ISO's) of North America and one of the three North American interconnection grids. The other two interconnection grids are the Western and Eastern Interconnections. It is responsible for coordinating the use of transmission lines and must guarantee the open and nondiscriminatory use of transmission lines for sellers and buyers of electricity; it has both real-time and long-term system monitoring in order to prevent thermal limits to be exceeded. In order to avoid blackouts and maintain the required voltages on the power grid, ERCOT continuously monitors real-time area load and balances the power generation and the demand. The energy supply and demand must always be balanced in order to prevent blackouts. The electricity produced cannot be stored; therefore the continuous challenge for ERCOT is to balance the demand and the supply. When the demand is higher than the supply customers with interruptible rates may be asked to shut down to meet the demand in order to balance the power on the grid (ERCOT, 2005b).

Emergencies such as load shedding, transmission and/or distribution congestion, and unexpected delivery schedules are solved by ERCOT. It also manages the transmission rate, controls the congestion on the transmission lines, schedules the energy transmission and distribution on the day-ahead market and is responsible for the accuracy of the "quantity" of energy delivered from the generation utility to the retail utilities and end-use customers (ERCOT, 2005b).

ERCOT is a non-profit organization and it has a fee of approximately $.4172 per MWh paid by the Qualified Schedule Entity (QSE). The QSE is responsible for submitting to ERCOT the energy demand and supply a day ahead of its delivery. It is the QSE that verifies that there will be enough electricity supply to meet the demand the following day. Different from other ISO's, ERCOT is only controlled by one public utility commission, the Public Utility Commission of Texas (PUCT). Other ISO's fees range from $.54 to $.98 per MWh. Among the six ISO's, only ERCOT and PJM (Pennsylvania, New Jersey, and Maryland) are also reliability regions. There are ten reliability regions in North America. Each reliability region ensures the standards given by the North American Reliability Council are met and ensures reliability in interconnections. A summary of the electricity market characteristics in the three previously mentioned states can be found on Table 4.

Table 4. Electricity Market Facts in California, PJM and Texas.

	California	PJM	Texas
Deregulation Date	January 1st, 1998	January 1st, 1999	January 1st, 2002
	Price To Beat (10% Reduction)	Price To Beat	Price To Beat (6% Reduction)
Region Condition	Importer	Exporter	NA (Texas is one of the three North American interconnection grids)
Capacity (MW)	44,000	59,000	77,000
Peak Demand (MW)	45,000	52,000	60,000
Margin Reserve		16-20%	17%
Primary Fuel for Power Generation	Natural Gas	Coal	Natural Gas
	Competitive Transition Charge	Transition Charge	Transition Charge
Type of Contracts	No long term contracts were allowed, all electricity should be sold in a day ahead market (Power Exchange Market)	All type of contracts were allowed including long term contracts	All type of contracts were allowed including long term contracts
Problems	Manipulation of the market. Environmental restrictions that affected new constructions of power plants.	Higher wholesale prices than the price to beat	

CHAPTER II

TEXAS MARKET CONDITIONS

A. Natural Gas

In Texas the majority of the power plants are fueled with natural gas. See Figure 6. Therefore, electricity pricing is directly affected by changes in prices of natural gas.

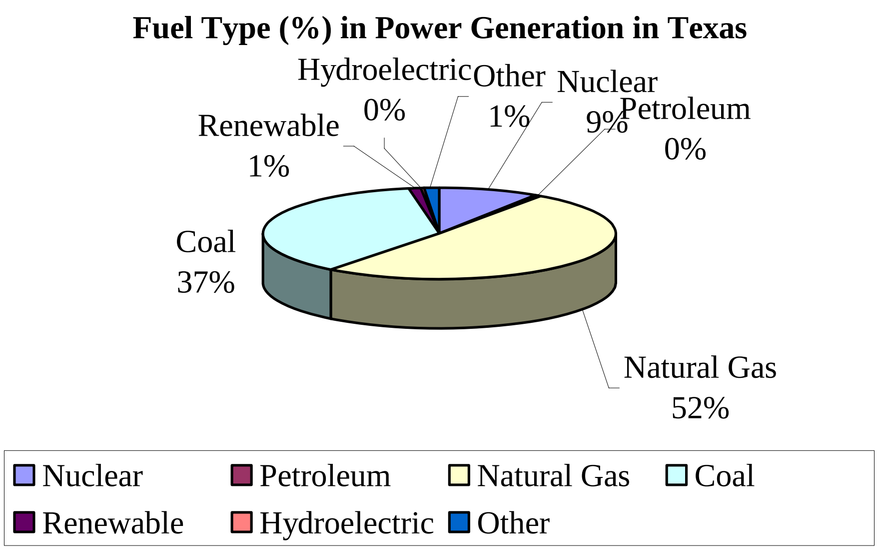

Figure 6. Fuel Type Percentage in Power Generation in Texas (EIA, 2006a)

Figure 7 shows how closely the industrial electricity prices in Texas match the profile of natural gas prices. The price of natural gas has increased dramatically in the last year, almost doubling its price and according to the US Energy Information Administration, natural gas prices are expected to remain high for the year 2006. See Figure 8.

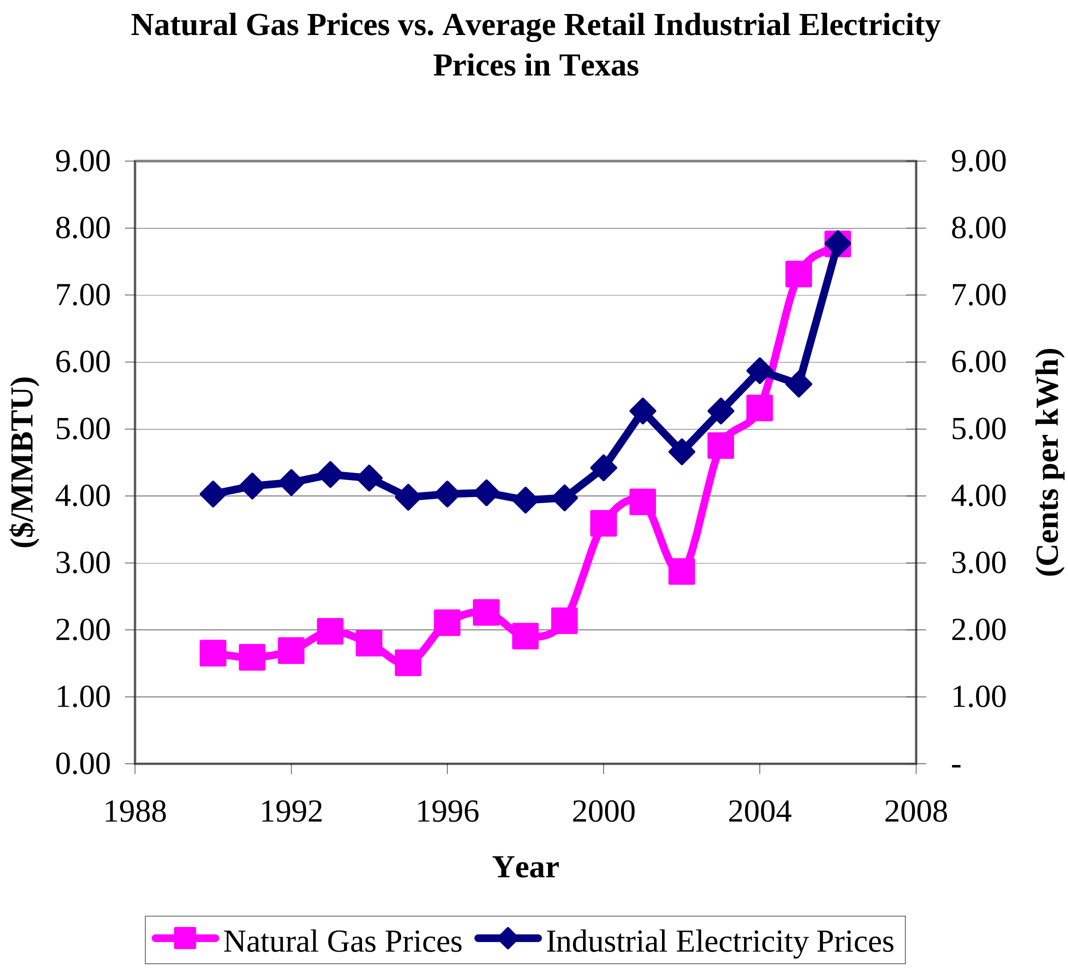

Figure 7. Natural Gas Prices vs. Average Retail Industrial Electricity Prices in Texas (EIA, 2006b) & (EIA, 2006c)

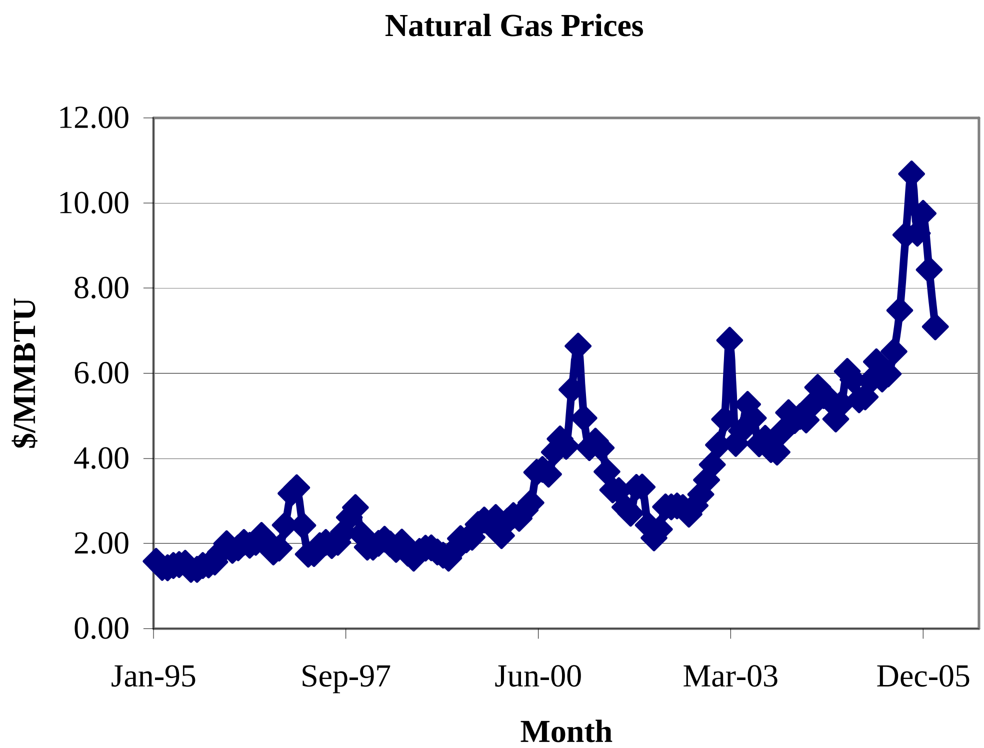

Figure 8. Natural Gas Prices (EIA, 2006c)

The changes in natural gas prices are unpredictable. Natural events, demand and supply affect the price of natural gas. In 2005, Hurricanes Katrina and Rita drove up energy prices in the USA. Natural gas production dropped nearly 15% because of the Gulf coast shutdowns and had not reached 2004 production levels by December 2005. See Figure 9. This affected natural gas prices dramatically since the Gulf Coast is one of the largest regions for oil and gas production in the US. In Louisiana, forty percent of natural gas production was stopped due to hurricanes. By the end of March 2006, pre-hurricane levels of natural gas production were mostly recovered; however it is expected that 400 million cubic feet per day will remain off line until June 2006, a four percent loss of daily production prior to Hurricanes Rita and Katrina (EIA, 2006d).

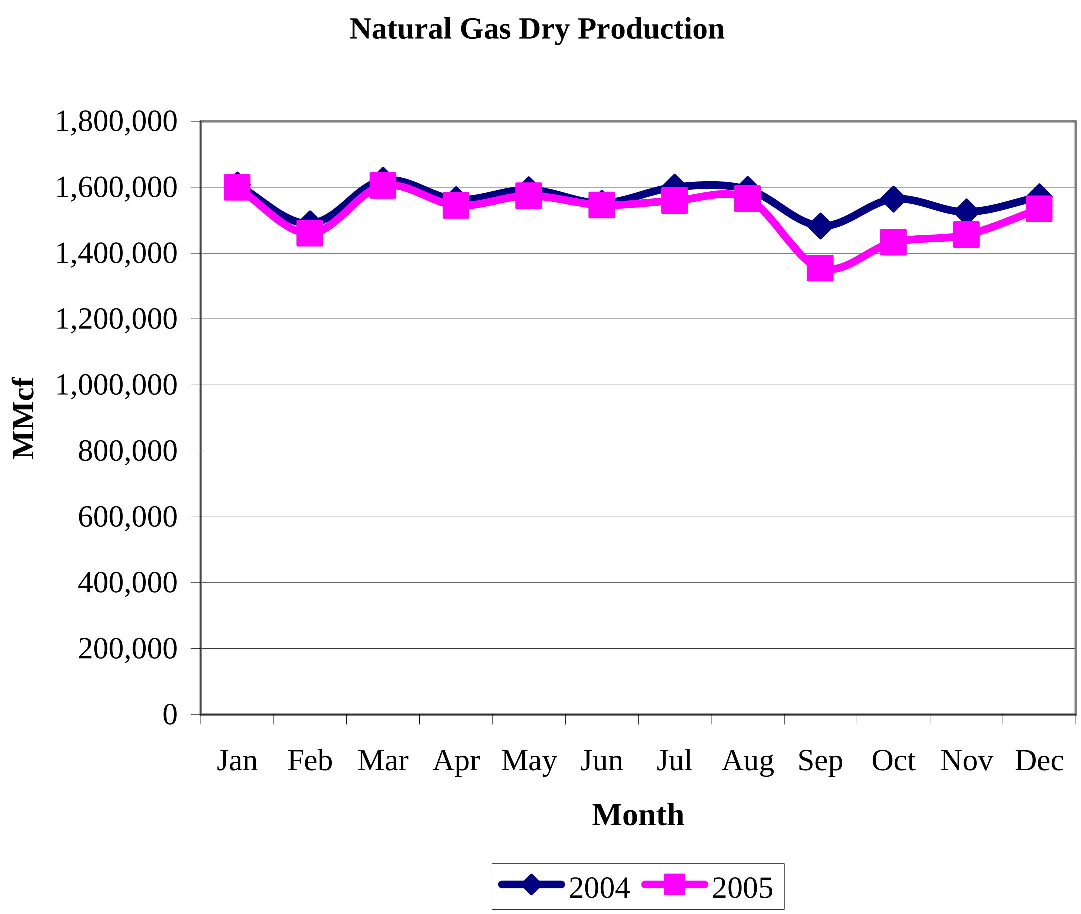

Figure 9. Natural Gas Dry Production (EIA, 2006e)

Despite the trend in high natural gas prices in 2005, by November and December the price began to stabilize due to mild winter temperatures. Higher temperatures in January increased the storage levels of natural gas and decreased the demand, therefore leading to a continued reduction in natural gas prices. The cold temperatures in March 2006 increased the price for natural gas. However, lower natural gas prices are predicted for the summer due to reduction in cooling demand. The low natural gas prices most likely will not last all year, because during the heating season, natural gas prices normally increase due to increases in demand. If there is a similar hurricane season to the one of 2005, natural gas prices will most likely increase significantly. Overall, the average price in 2006 for natural gas prices is estimated to be lower than the average price in 2005. In 2007 the average price for natural gas is projected to be higher than the price in 2006 (EIA, 2006d). Prices of natural gas in the USA can be seen in Figures 10 & 11.

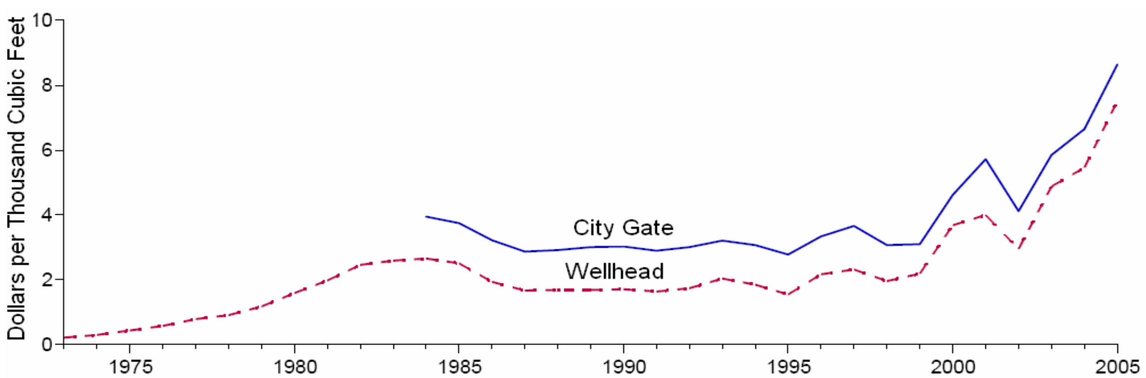

Figure 10. Natural Gas Prices in Dollars per Thousand Cubic Feet (EIA, 2005)

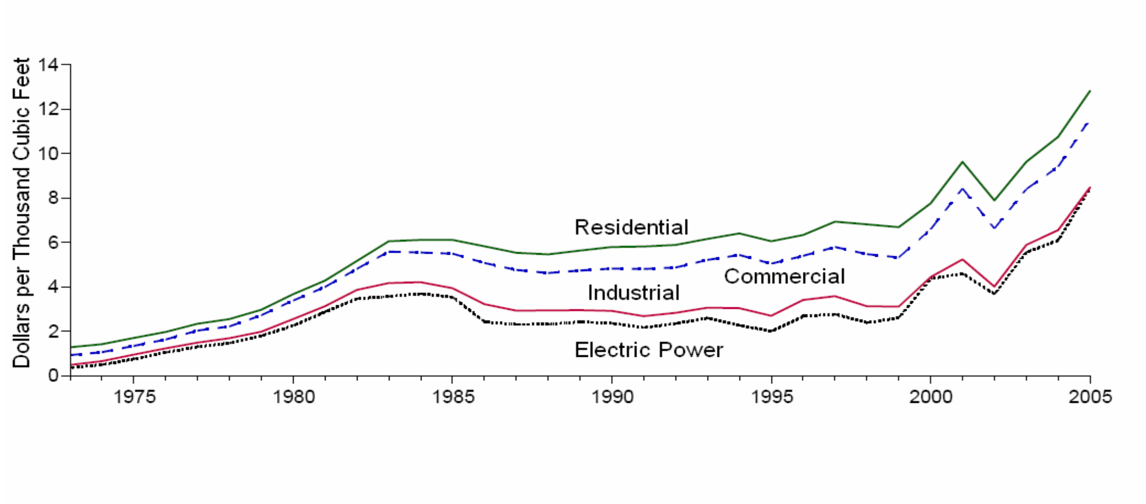

Figure 11. Natural Gas Prices per Thousand Cubic Feet by Sector (EIA, 2005)

CHAPTER III

ELECTRICITY PRICING STRUCTURE

Electricity bills are comprised of different type of charges. The first one is the energy charge, dollars per total kWh consumed. This is usually the highest part of the bill, especially in accounts with high-energy consumption. This charge is determined by the cost of generation which usually is around two thirds of the bill. The second type of charge is the demand charge, dollars per kW, embedded within the transmission and distribution charges. For accounts with high-energy consumption this charge amounts to less than 30% of the total bill. However, in a low energy consumption account with a high demand, this charge may account for the more than 60% of the total costs of the bill. The kW for the transmission charge for an account with a peak demand of 1000 kW or higher is the 4CP kW, determined by the largest 15-minute kW during ERCOT's 15-minute peak time from June to September. This charge will be fixed for the following year. If the 4 CP is not determined for a customer the transmission charge will be based on the NCP kW. The NCP kW is the highest kW supplied in a 15-minute interval during that month (PUCT, 2006).

The kW for the distribution charges will either be the NCP for the current billing month or 80% of the highest monthly NCP kW in the previous 11 months, whichever is higher. Transmission and distribution charges vary for residential, industrial and commercial customers (PUCT, 2006). Residential customers pay transmission and distribution charges per kWh consumed and no demand charges. Customers with a peak demand of 1000 kW or higher have higher demand charges than customers with a demand greater than 10kW but less than 1000 kW.

There are other expenses in the bill such as the firm point-to-point transmission charge, system benefit fund, nuclear decommissioning and transition charges. The transition charges are applied to customers within a certain region whether the affiliated transmission company is serving them or not. The transition charges are to be used until stranded costs are recovered but no longer than 15 years from the issuance of transition bonds. The system benefit fund is charged per kWh, the nuclear decommissioning is charged per kWh for residential and secondary customers, those with a service greater than 10 kW but less than 1000 kW. For other types of customers the nuclear decommissioning is charged per kW. Small costumers are those with a demand of 10 kW or less. Secondary customers are those that require 12,470 Volts for electricity delivery and primary customers are those who need between 12,470 volts to 60,000 volts for electricity delivery (PUCT, 2006).

There is a 20% reduction in the total cost of transmission, distribution, system benefit fund and nuclear decommissioning charges for four-year universities or colleges in Texas (PUCT, 2006).

It is very important to choose the appropriate contract for electricity. In doing so it is important to remember that electricity trades several times before being delivered to the end-use customer, which can double or triple the electricity price. Choosing the wrong electricity contract may result in millions of additional dollars spent. Electricity contracts have three significant agreements. These are the amount of electricity being sold, the price for the electricity (flat rate, time of day, etc) and Swing, a fixed amount of electricity to be consumed per month within certain limits. Usually +/-10%, to avoid paying penalties in the contract and at the same time giving some security to the electricity provider. The electricity profile will have a direct impact on the energy charge.

CHAPTER IV

TYPES OF CONTRACTS

A. Forward Contracts

The most common type of contract is the one where a fixed flat rate for electricity is agreed over a period of time, known as a forward contract. This type of long-term contract helps reduce the risk of unforeseen high electricity prices. Long-term contracts avoid risk for the end-use customer since the price to be paid over a certain period will remain fixed. Figure 12 shows the average retail electricity prices by Sector in the USA. Although the price increases in the past ten years (1995-2005) are not as dramatic as those experienced from 1975-1985, forward contracts do provide the consumers with price guarantees over the term of the contract.

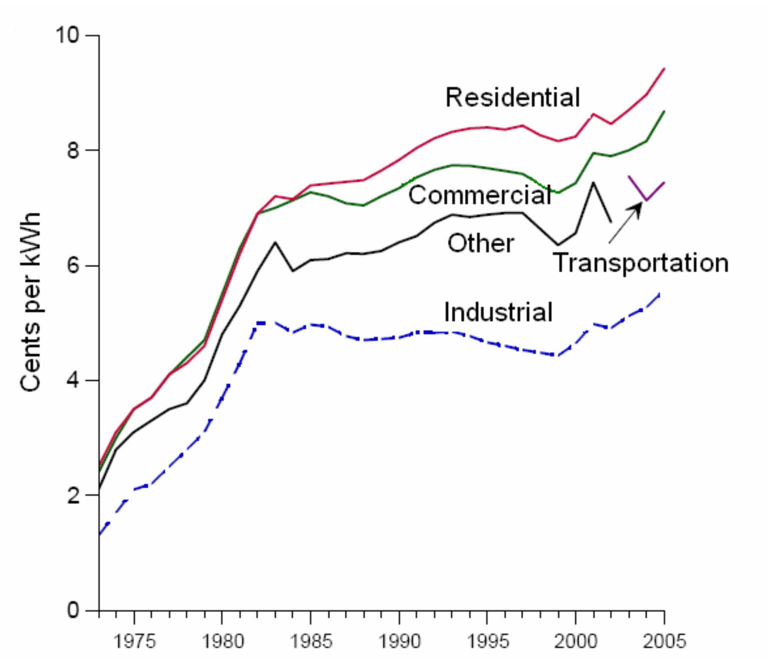

Figure 12. Retail Average Prices of Electricity by Sectors (EIA, 2005)

B. Competitive Pool Contracts

Without a long-term contract, electricity must be purchased on the spot market and the customer must pay the Market Clearing Price for Energy also known as the MCPE. The MCPE was created after deregulation, and it changes every 15 minutes depending on the demand, supply, fuel costs and congestion on transmission lines. Every 15 minutes the power generators bid the excess quantity of electricity generated. ERCOT will start accepting the bids from low to high price. The highest price accepted by ERCOT in order to meet demand will determine the MCPE price and will be paid to all power generators. Sometimes, when supply is greater than demand generators will pay customers to consume their electrical power to avoid costs in ramping generators down in the power plant. In this case, the MCPE will have a negative value. The MCPE also depends on the zone it is delivered.

The contract in which all electricity consumed is purchased on the spot market is called "Competitive Pool" contract. Under this type of contract, if the demand is greater than the supply there is no pressure whatsoever to reduce the costs of electricity, as was seen in California. However, if the demand is lower than the supply, the electricity providers have pressure to lower their costs. At the same time, having a competitive pool contract available without a long-term contract would make it very difficult for new power plant investors to recover capital costs. Prices in the spot market can increase by forty percent during peak times compared to off-peak times. Even a small change in demand could increase significantly the price in the spot market. Although the MCPE in

Texas has been somewhat steady, prices have been seen as high as $990 per MWh (ERCOT, 2006c)(February 24th, 2003 due to an ice storm).

The amount of electricity bought on the MCPE in Texas is low, since most of the electricity in Texas is provided by Retail Electric Providers who have purchased fixed quantities of electricity. ERCOT continuously balances the quantity of demand and supply of electricity. When necessary, electricity is bought on the MCPE to maintain the balance between supply and demand within ERCOT's region. At the same time, transmission has an impact on the spot market in the way that if a line is already under stress, no load can be transferred through it, and energy will have to be purchased from a different power generator which may increase the electricity price.

The MCPE can have a competitive price, for the years 2003 and 2004 the MCPE average was $36.5 per MWh. However, purchasing electricity on the spot market, that is paying the MCPE, can bring considerably higher prices. In February 2003, the MCPE average for that month was $80 per MWh, considerably higher compared to other electricity prices. By looking at Figure 13, it can be seen that the MCPE was steady for most of the years 2003 and 2004. Prices started increasing significantly in 2005.

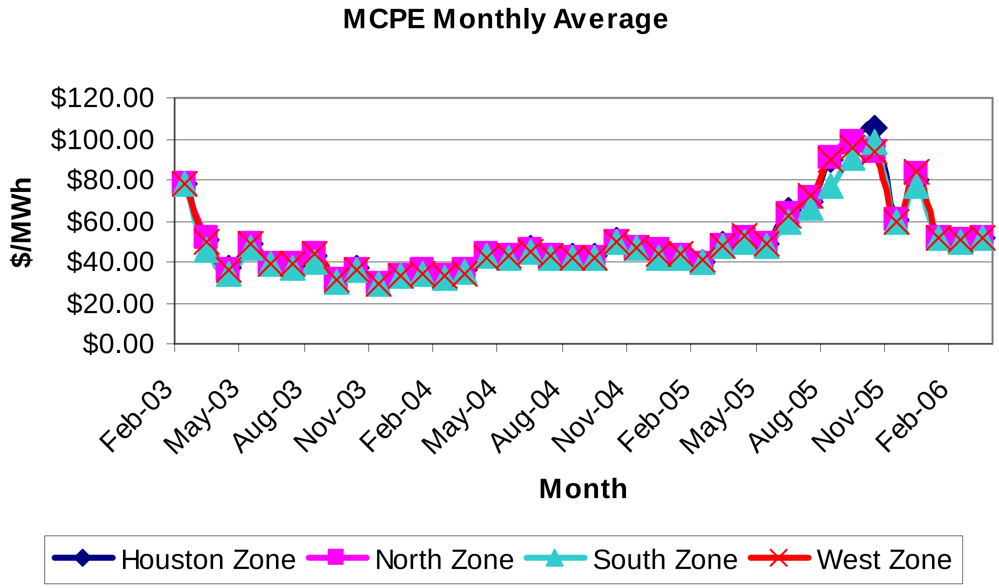

Figure 13. MCPE Monthly Average (ERCOT, 2006d)

The MCPE will usually be the highest price of electricity being delivered to the market, especially during peak hours. A customer must pay the adder in addition to the MCPE when purchasing electricity on the spot market. An adder includes all ancillary services, supply and capacity charges. Ancillary services are those that ensure the reliability and capacity of the transmission system and it includes the spinning reserves, non-spinning reserves, load regulation, replacement reserves, etc. Small changes in peak demand can cause high MCPE prices. Research from The Electric Power Research Institute has found that a 2.5% decrease in peak demand causes a reduction of 24% in wholesale prices. However, if the peak demand increases, wholesale prices can double or as it was the case in California wholesale prices can be ten times higher. The MCPE depends on many factors and it is very difficult to predict how it will act in the future. The MCPE price is directly affected by natural gas prices. Figure 7 shows similar profiles for the MCPE and natural gas prices. At the same time, an interruption in a transmission line can also increase the MCPE value significantly.

C. Day Ahead Market Contracts

In addition to the spot market there is the day-ahead market. The day-ahead market is controlled by ERCOT. The day-ahead price is determined depending upon the energy supply, demand, and transmission constraints for the following day. The real-time, spot market prices (MCPE) are higher due to unforeseen events like high loads, transmission congestion, and forced outages for generating plants. The day-ahead market will give ERCOT the opportunity to schedule and balance demand and supply a day prior to delivery. In this way, ERCOT prevents exceeding thermal (heating) limits, manages congestion zones and provides sufficient load to meet the demand. Giving ERCOT a day in advance to arrange the electricity delivery removes some of the volatility in energy prices; however, long-term contracts where all events have been planned with more anticipation usually have lower prices than the prices on the day-ahead market. For purchasing electricity on the day-ahead market, a retail electric provider charges an ancillary charge (includes congestion charges, spinning reserves, non-spinning reserves, etc) per MWh.

D. Heat Rate Index Contracts

An alternative approach to determine the energy rate for a contract is the heat rate index. In this type of contract the energy rate is determined by multiplying the heat rate index times the price of natural gas. An adder is also added to determine the price of energy. For example, if the heat rate index is 8, the adder is $20 dollars per MWh, and the natural gas price is \$9 dollars per MCF, the energy charge would be \$92 dollars per MWh. The natural gas price needs to be monitored daily and can be found on websites such as www.platts.com. In this type of contract, the customer agrees to a heat rate index (MMBTU/MWh), in Texas the heat rate is usually between 7 and 9, and then chooses the day, according to the natural gas price, to "lock in" a natural gas price to purchase electricity for a period of time. The period of time can be one month, a couple of months, a year or the entire contract time. The heat rate in Texas is typically lower in the winter than in the summer. The customer can take advantage of low natural gas prices by locking in lower natural gas prices. However, high natural gas prices make this type of contract not beneficial to the customer. High natural gas prices will determine very high-energy prices. At the moment, the heat rate index contract is not beneficial unless natural gas prices start going down. The heat rate method can be unpredictable and volatile.

E. Take or Pay Contracts

Another type of contract is the "Take or Pay" contract, in which a customer agrees to purchase a fixed amount of electricity defined in a block at a fixed rate, and whatever the customer consumes exceeding the block size must be purchased on the spot market. The block structure is defined by a fixed amount of energy to be purchased at a fixed rate for some days of the week at specific times. For example, a 7 X 24 block structure will purchase a fixed amount of electricity per hour for a fixed rate seven days a week, 24 hours a day. A 5 X 16 block structure will purchase a fixed amount of electricity per hour for a fixed rate five days a week (Monday-Friday), 16 hours per day (6 am – 10 pm). The block structure to purchase electricity will depend on the energy consumption and the type of facility. The amount of electricity in the block must be paid even if the end-use customer is consuming less electricity than the amount of electricity in the block and an adder is also added for each kWh delivered.

This type of contract presents less risk for electricity providers and it may decrease the pressure to improve efficiency of the system. If the power generator already knows in advance that a fixed amount of electricity will be purchased no matter what, this takes away the incentive to lower costs or improve the efficiency of the plant (Onofri, 2003). There can be different types of block rates: the declining block rate and the increasing block rate. The declining block rate will decrease the energy charge as more energy is purchased, and the increasing block rate will increase the energy price as more energy is purchased.

F. On and Off Season Contracts (Tiered Pricing)

The tiered price is composed of on-peak and off-peak fixed rates, giving the customer the opportunity to purchase electricity at two different rates. One is for the on-peak period (ERCOT's on-peak period is from 6 am to 10 pm during weekdays) and another one for the off-peak period (ERCOT's off-peak period is composed of weekends, holidays, and from 10 pm to 6 am during weekdays). On/Off-peak periods may change from ERCOT's schedule if agreed by the REP and the end-use customer. On/Off-peak periods may also vary for summer and winter. Having real-time interval data gives the customer the opportunity to analyze what type of contract would be beneficial and manage the peak demand time. Savings may be obtained by shifting on-peak load to off-peak loads. Thermal storage systems may be considered to obtain savings by reducing the peak demand on-peak and shifting part of the load to off-peak schedules.

CHAPTER V

OPTIONS FOR REDUCING ELECTRICITY COSTS

A. Electricity Supply Curtailment

Contracts may have certain conditions that may decrease the electricity price such as customers who decide that all their load or part of their load may be curtailed during congestion and peak times. In some type of contracts, the electric provider has to inform the customer in advance (one hour, two hour, etc) prior to stopping the service.

B. Aggregation of Loads

Aggregation of different types of loads in a long-term contract may reduce the price of electricity. One of the reasons is the improvement on the overall load factor. The load factor is defined as the ratio of the average demand to the peak demand. The longer time the demand is close to the peak demand, the higher the load factor will be and the energy charge will be lower. By aggregating loads, the load factor may improve. If the load is maintained closer to the peak demand, the generation facility will not have to increase its production to supply the extra power for the peak demand, therefore avoiding increasing the cost of energy production, resulting in better energy charges. By decreasing the amount of energy needed to meet the peak demand, energy charges decrease. The overall peak demand may take place at a different time from each individual peak demand, obtaining a flatter energy profile and resulting in lower energy charges.

$$Load\ Factor = \frac{average\ kW}{\max kW}$$

$$average\ kW = \frac{kWh\ used}{24\ hours \times billing\ days}$$

If the load factor is less than 70 to 80% it means that there are significant periods of high electrical usage. Another factor to consider in aggregating loads is that the larger loads tend to increase the number of REPs interested in competing for the contract. This competition lowers the final cost. A final benefit of aggregation is that monthly swings can be settled on the total quantities purchased. Each individual entity in the aggregation would not be subject to meeting the swing limits, as long as the aggregate totals were within the swing limits.

C. Power Factor (PF)

The electricity bills are also affected by the power factor. The power factor is the ratio between the active power and the apparent power. The active power is the real power, which is the power that is actually being consumed by the end-use customer. The apparent power is the power needed to maintain the proper magnetic field to deliver the active power. The power factor measures how efficiently the electricity is being delivered to the customer; it shows how much power is needed to deliver the power consumed by the customer. The lower the power factor is, the more expensive it is to provide electricity to the customer and the transmission and distribution provider may assess a penalty unless the facility has taken measures to correct a poor power factor. A low power factor will make the electric system less efficient. Therefore, a minimum power factor is required. The power factor typically varies from 0.8 to 0.9, unless capacitors are added to improve the power factor. Currently several T&D providers in Texas are charging for PF less than 0.95.

D. Meter Consolidation

An additional important factor to consider is the diversity factor, which is the ratio of the sum of the individual maximum demands of a group to the maximum demand of the whole system. The higher the diversity factor, the lower transmission and distribution rates. A low diversity factor will cause a high rate of transformer burnouts. A high diversity factor indicates that a greater number of customers can be supplied for a given station at maximum demand and so lower prices are offered to the customer. At a given location or site, there may be multiple meters serving different buildings. Each meter will have a meter charge, energy charge, demand charge, as well as other T&D charges. If the building/site meters can be consolidated, it may be possible to reduce metered demand, because of diversity, and improve the metered load factor. Energy costs will not be lowered, but billing charges may be reduced.

CHAPTER VI

TEXAS A&M UNIVERSITY SYSTEM ELECTRICITY AGGREGATION PROJECT

A. Texas A&M University System

The Texas A&M University System (TAMUS) is composed of nine universities, a health science center and seven state agencies. It has more than $500 million in research and over 101,000 students. The nine universities that compose the Texas A&M system, also referred as TAMUS, are Prairie View A&M University, Tarleton State University, Texas A&M International University, Texas A&M University, Texas A&M University in Commerce, Texas A&M University in Corpus Christi, Texas A&M University in Texarkana, Texas A&M University in Kingsville, and West Texas A&M University. The agencies are the Texas Agricultural Experiment Station (TAES), Texas Cooperative extension (TCE), Texas Engineering Experiment Station (TEES), Texas Engineering Extension Service (TEEX), Texas Forest Service (TFS), Texas Transportation Institute (TTI) and the Texas Veterinary Medical Diagnostic Laboratory (TVMDL).

B. Participating System Entities

The electricity loads for the six large universities within ERCOT-Texas A&M-Kingsville, Texas A&M-Corpus Christi, Texas A&M-International University, Texas A&M-Galveston, Texas A&M-Commerce and Tarleton, were initially included in the November 2001 contract. Only the larger, IDR-metered accounts were included in the first procurement. The smaller monthly (scalar) meters were on the deregulated “price-to-beat" and qualified for the automatic six percent price reduction from 2001 energy prices.

Texas A&M University in College Station has long been considered a wholesale purchaser of electricity and is located in a municipal utility service area. Prairie View A&M University is served by an electrical cooperative, and West Texas and Texarkana are not within ERCOT. Therefore, those universities were not included in the TAMUS aggregation program. The facilities from TEEX, TAES, and TCE that are in ERCOT, along with the Institute of Biosciences and technology (IBT) and the Prairie View A&M University Nursing School, both in Houston, were added to the TAMUS aggregation at various times after initial contract. In addition, Stephen F. Austin University, joined the TAMUS aggregation for the fiscal year 2006 purchase.

CHAPTER VII

FACILITIES DESCRIPTION AND LOAD PROFILES

Annually the Texas A&M University System along with Stephen F. Austin (SFA) University consume approximately 250,000 MWh. Monthly energy consumption percentages can be found in Table 5. SFA consumes around 33% percent of the total load followed by Texas A&M University in Kingsville with approximately 14% of the total load. Tarleton State University and Texas A&M University in Corpus Christi consume 12%, and 13% of the total load respectively. Texas A&M University at Galveston, the IBT facility in Houston and one meter located in Commerce, Co 8, have the lowest energy consumption, approximately 4%, 3%, and 2% respectively. Each university's location within the ERCOT zone can be found in Figure 14.

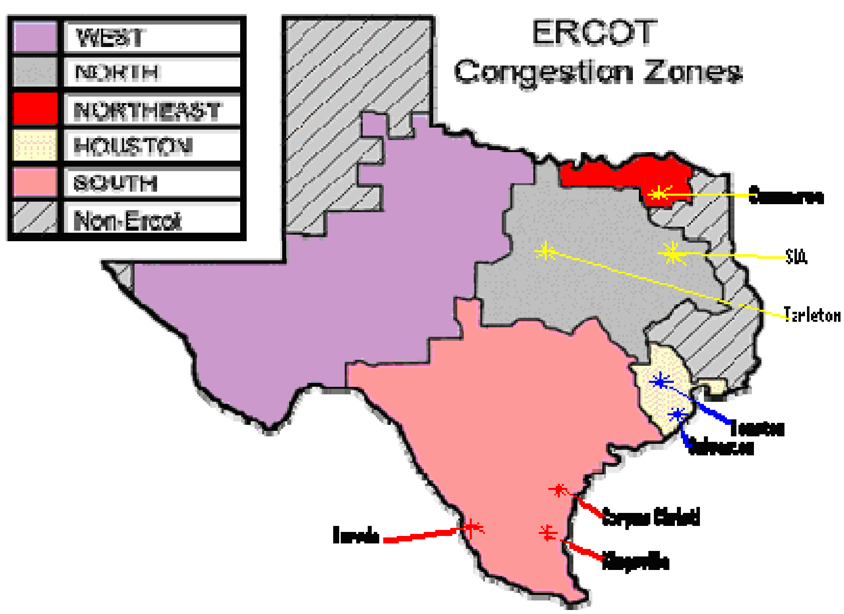

Figure 14. Universities Location on ERCOT's Zone

Table 5. Load Percentage of the Total Aggregated Load by University

	Gal	IBT	Co 7	Co 8	Kings	Tarleton	Laredo	SFA	Corpus
Mar-05	4.5%	3.5%	9.5%	2.0%	15.1%	12.3%	7.4%	33.3%	12.5%
Apr-05	4.8%	3.2%	9.6%	2.0%	14.4%	12.0%	7.9%	33.5%	12.6%
May-05	4.7%	3.2%	10.3%	2.3%	14.2%	11.3%	8.5%	32.8%	12.7%
Jun-05	4.1%	3.0%	10.8%	2.6%	14.3%	12.3%	8.4%	31.5%	13.0%
Jul-05	5.4%	2.9%	10.2%	2.6%	14.5%	12.4%	8.2%	30.6%	13.3%
Aug-05	5.1%	2.9%	10.6%	2.6%	13.9%	12.2%	8.5%	30.8%	13.4%
Sep-05	3.8%	2.7%	10.6%	2.2%	14.5%	12.7%	8.1%	31.2%	14.3%
Oct-05	4.0%	3.0%	10.2%	2.4%	14.9%	12.2%	8.0%	31.4%	14.0%
Nov-05	3.9%	3.1%	9.8%	2.2%	14.5%	12.6%	7.7%	32.6%	13.7%
Dec-05	3.3%	3.6%	10.0%	2.2%	15.2%	12.5%	7.4%	32.9%	13.0%
Jan-06	3.5%	3.5%	9.6%	2.0%	15.5%	12.5%	7.4%	32.8%	13.3%
Feb-06	3.0%	3.5%	10.1%	2.4%	9.9%	13.9%	7.8%	35.5%	14.0%

A. Texas A&M University at Corpus Christi

Texas A&M University at Corpus Christi (TAMU- CC) is a 1,162,399 gross square feet campus, located on a 240-acre island. It has approximately 7,000 students, approximately eighteen academic buildings, one student union building, two recreational facilities, one state office building, fourteen housing units, and an additional fourteen buildings for services purposes. Texas A&M at Corpus Christi is located within the South Zone of ERCOT, and AEP (American Electric Power) provides the transmission and distribution services.

Texas A&M at Corpus Christi is a unique site because it has a large chilled water thermal storage system. The thermal storage system uses water as the storage medium, where water is cooled during the night, stored in an insulated tank and then discharged during the day to reduce energy demand. The process of cooling water and storing it in the insulated tank is called the recharging process, and the use of the stored cooled water is called the discharging process. The storage tanks are recharged at night to take advantage of lower, off-peak, electricity prices and discharged during the day to reduce the energy consumption during on-peak rates. Due to Corpus Christi's storage system, electricity is purchased on the tiered price structure. Tiered pricing consists of summer and winter off-peak and on-peak pricing.

The Corpus Christi campus consumed 32,526,178 kWh from March 1st, 2005 to February 28th, 2006. The greatest monthly energy consumption took place in September with 3,348,760 kWh, followed by August with 3,346,960 kWh. The lowest monthly energy consumption took place in February 2006 with 2,290,055 kWh. See Table 6.

Table 6. Corpus Christi Monthly Consumption

Corpus Christi Monthly Consumption		
Total Monthly Energy Consumption (kWh)	**Mar-05**	2,312,682.48
	Apr-05	2,463,880.32
	May-05	2,545,880.40
	Jun-05	2,853,810.72
	Jul-05	3,021,167.52
	Aug-05	3,346,960.08
	Sep-05	3,348,760.32
	Oct-05	3,066,564.48
	Nov-05	2,661,527.04
	Dec-05	2,237,283.84
	Jan-06	2,377,606.08
	Feb-06	2,290,055.04
TOTAL		32,526,178.32

From the total energy consumed from March 1 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 15 for an average of energy consumption for these periods for different months. From the 69% of energy consumed from 6 am to 10 pm, 17% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 52% of its total load during on-peak hours and 48% during off-peak time. From the fiscal year 2006 electricity purchase, the ESL proposed and Sempra Energy Solutions agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 42% of the total energy during peak periods and 58% during off-peak times from September 1, 2005 to February 28, 2006, the time period for this detailed analysis.

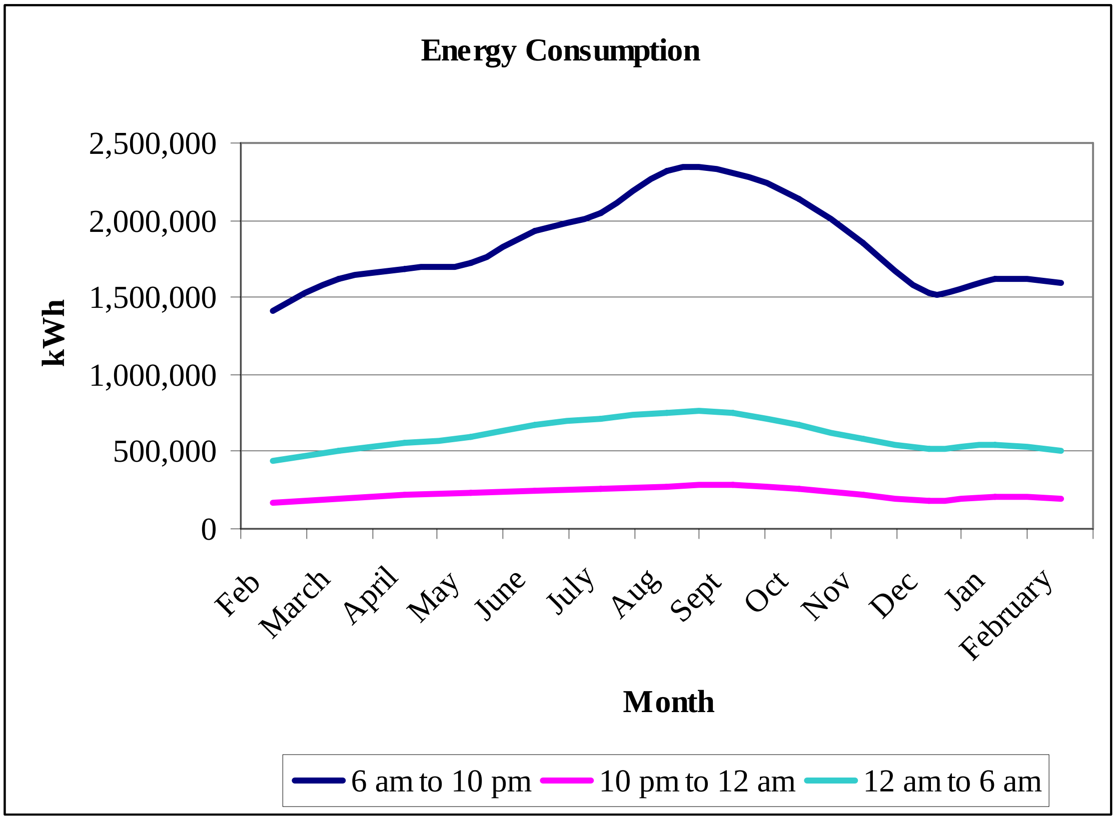

Figure 15. Corpus Christi Monthly Energy Consumption for Different Months

In the months of February and March the peak demand during weekdays varied from 3600 to 4100 kW. From April to July the peak demand varied from 4100 kW to a little over 5000 kW. From July to September the peak demand varied from 4900 kW to 6100 kW, during October and November the peak demand varied from 4100 kW to 6000 kW, and in December the peak demand varied from 2400 to 4600 kW. Most of the time, the peak demand occurred around 9 pm.

A thermal storage system gives the opportunity to have a flatter energy consumption profile by distributing the energy consumption throughout the day. Ideally, the storage tank is charged (chillers are on) during the lowest period of energy consumption and discharged (chillers are off) during the highest period of energy consumption. The energy consumption during on-peak times (usually from 3 to 6 pm) can be reduced by turning off chillers and discharging the water of the storage tank. This will reduce both the energy and transmission charges. The chillers are run during the period with the lowest energy consumption (typically from midnight to 6 am), avoiding high peaks that would alter the flatter energy consumption profile, preventing high distribution charges. The thermal plant in Corpus Christi has 4 chillers.

The thermal storage system in Corpus Christi could bring extra savings if the on-peak demand could be lowered, reducing demand and energy charges. During February 14 days out of 22 weekdays had the peak demand during the day; in March 15 days out of 23 days had the peak demand on-peak; in April only two days out of 21 days had the peak demand during off-peak time; in May only 5 days out of 22 had the peak demand during off-peak periods; in June only 3 days out of 22 had the peak demand during off-peak time; July and August had only one day out of 21 and 23 weekdays respectively, with a peak demand during off-peak time. In September 13 days out of 22, in October 9 days out of 21, in November 11 days out of 22 and in December 16 days out of 22 had peak demands during off-peak periods.

From March 1 to August 15, 2005, the on-peak time was considered to be 6 am to 10 pm during weekdays, corresponding to ERCOT's peak time. In the fiscal year 2006 contract, the on-peak time was negotiated with the retail electric provider (Sempra Energy) to be 6 am to 7 pm, weekdays. Therefore, there were more peak demands during off-peak time.

Overall, the peak demand during weekdays typically occurred from 9 am to 9 pm and from 2 pm to 2 am during the weekends. In general, the lowest consumption of energy during weekdays occurred early morning, most of the time from 5 am to 6 am. During the weekends, the lowest energy consumption occurred in early morning, most of the time from 8 am to 9 am. The lowest energy consumption varied from 1800 to 3000 kW during January, February, March, December and January. See Figures 16 through 21 for Corpus Christi weekdays and weekends average energy profiles.

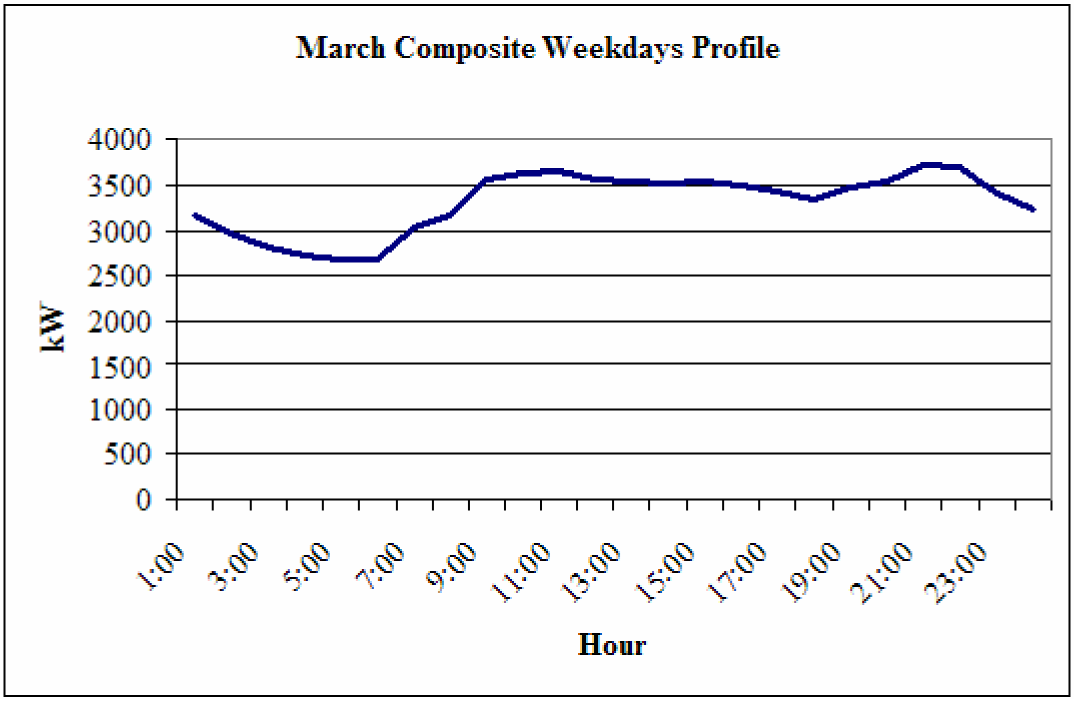

Figure 16. Corpus March Weekday Average Energy Profile

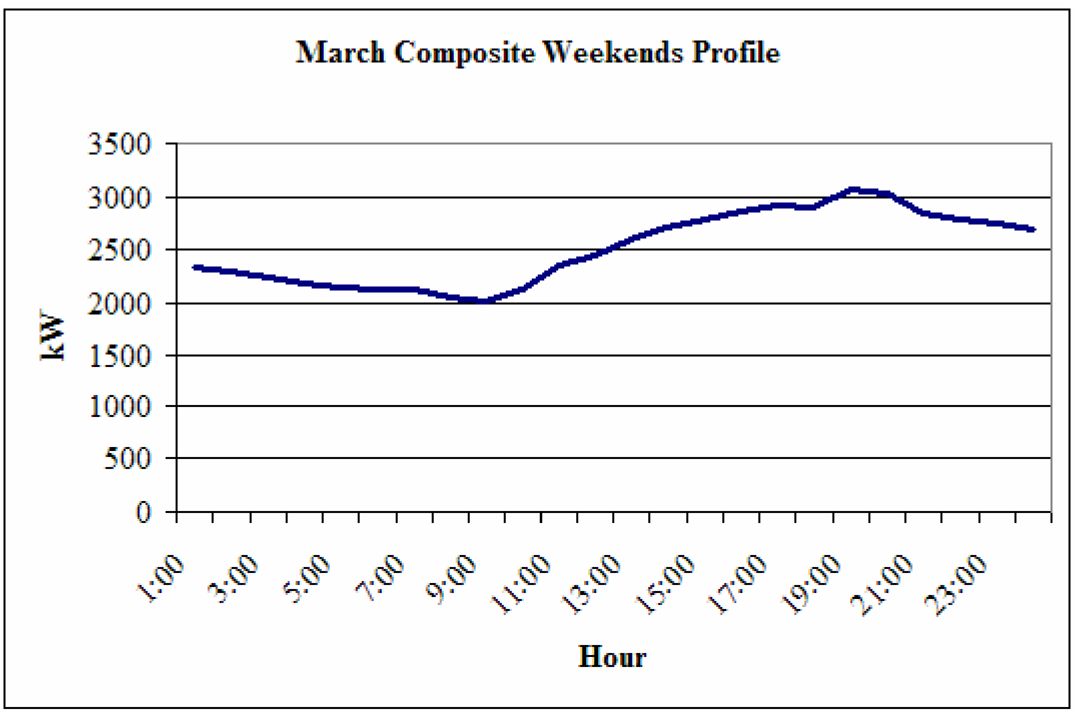

Figure 17. Corpus March Weekend Average Energy Profile

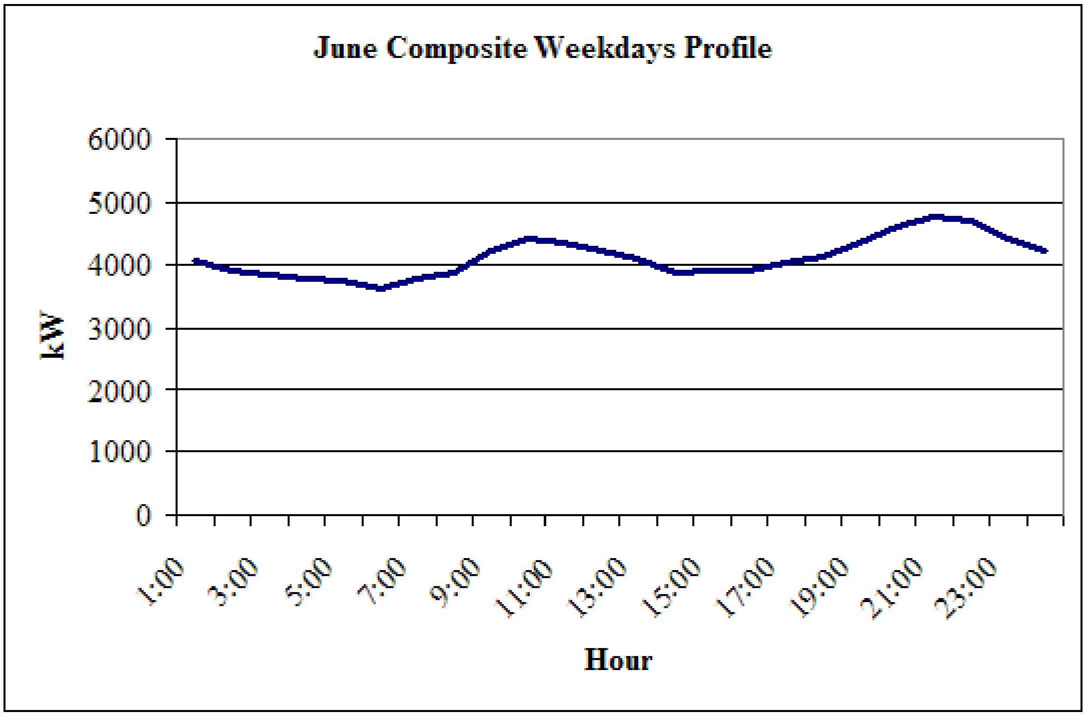

Figure 18. Corpus June Weekday Average Energy Profile

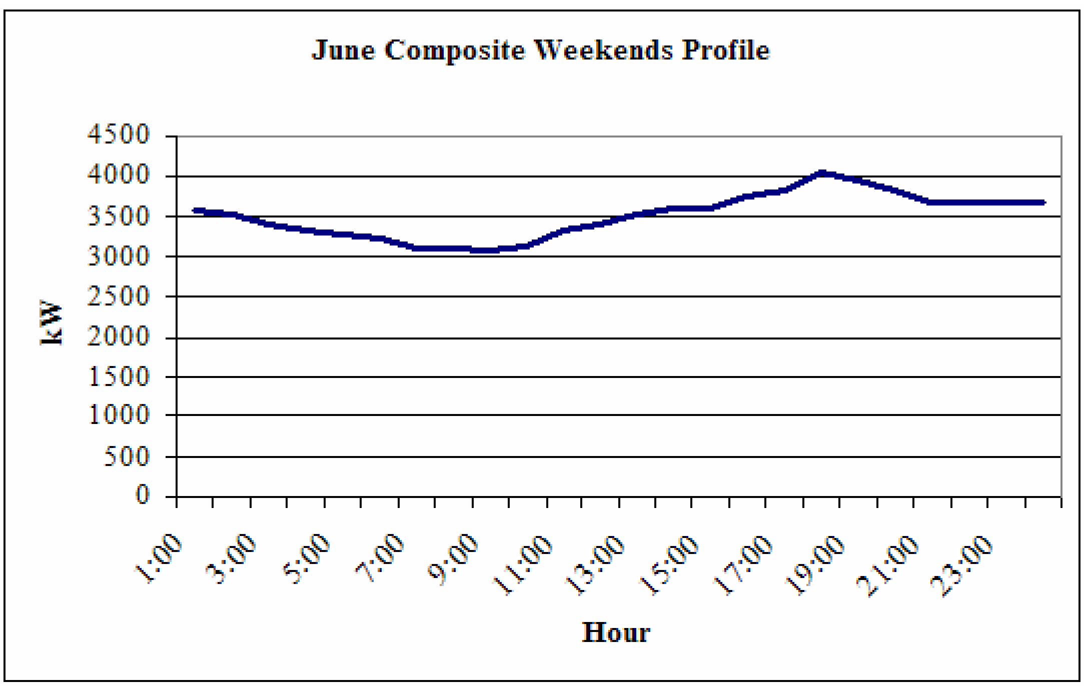

Figure 19. Corpus June Weekend Average Energy Profile

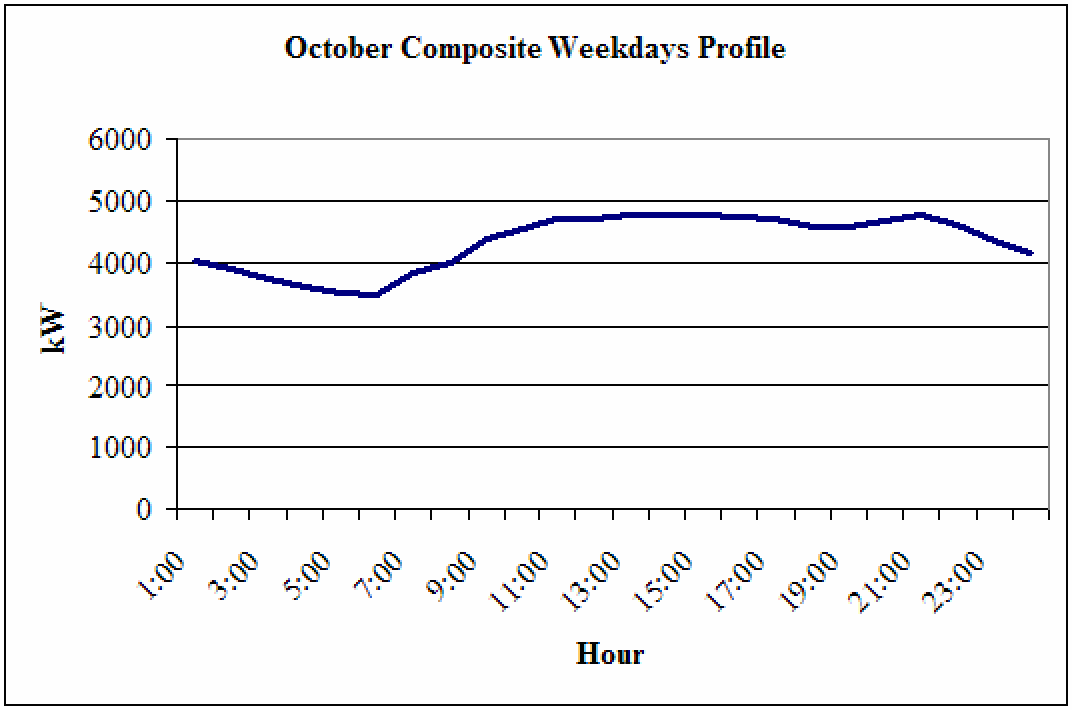

Figure 20. Corpus October Weekday Average Energy Profile

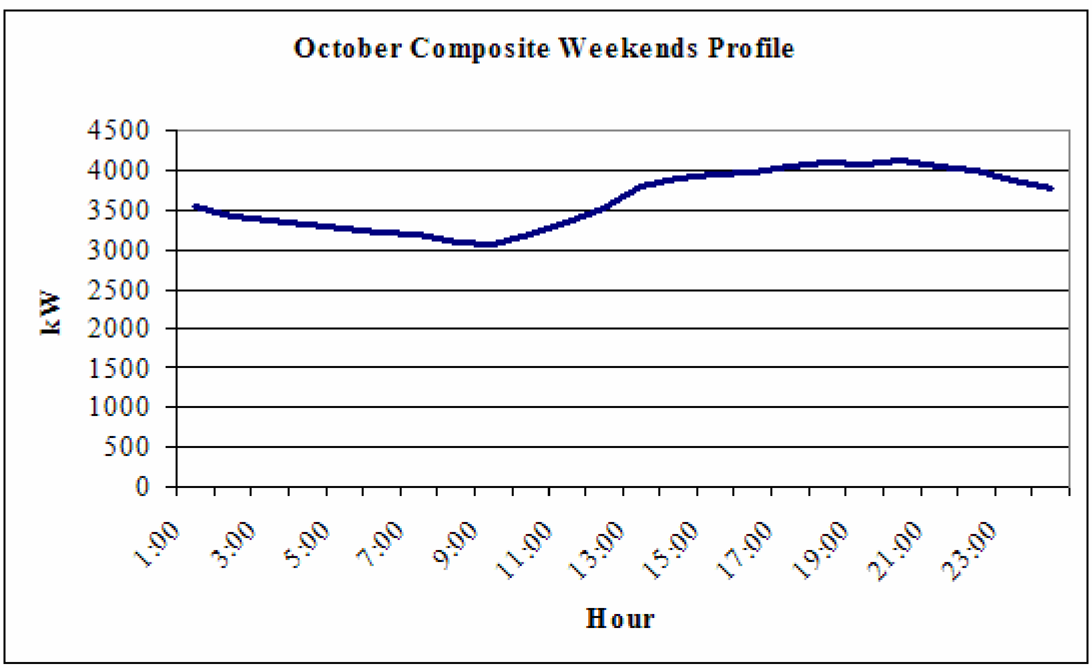

Figure 21. Corpus October Weekend Average Energy Profile

B. Texas A&M University at Galveston

The Texas A&M campus at Galveston (TAMU- Galveston) has over 1,400 hundred students. There are 3 campuses on Galveston. The Mitchell campus covers 130 acres on Pelican Island, and it has 14 major buildings, three residence halls (for more than 600 students), a physical education facility, and the Mary Moody Northern Student Center. The second campus in Galveston is the 3-acre Ft. Crocket Campus with an additional 15,200 square feet leased by the National Marine Fisheries Services for Marine Laboratory research. Finally, the 10-acre Offatts Bayou campus in Galveston is used for Marine training and recreational activities.

The Texas A&M campus at Galveston is located within the Houston Zone of ERCOT, and Center Point Energy provides the transmission and distribution services. The Galveston campus consumed 10,285,761 kWh from March 2005 to February 2006. The greatest consumption was in July with 1,228,655 kWh followed by August with 1,224,613 kWh. The lowest monthly energy consumption took place in February 2006, with 484,186 kWh. See Table 7.

Table 7. Galveston Monthly Energy Consumption

Galveston		
Total Monthly Energy Consumption (kWh)	**Mar-05**	840,894
	Apr-05	938,837
	May-05	949,934
	Jun-05	889,656
	Jul-05	1,228,656
	Aug-05	1,224,613
	Sep-05	897,688
	Oct-05	880,647
	Nov-05	760,038
	Dec-05	564,681
	Jan-06	625,932
	Feb-06	484,186
TOTAL		10,285,761

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 22 for an average of energy consumption for these periods for each month. From the 69% of energy consumed from 6 am to 10 pm, 19% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 50% of its total load during on-peak hours and 50% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 41% of the total energy during peak periods and 59% during off-peak times from September 1, 2005 to February 28, 2006.

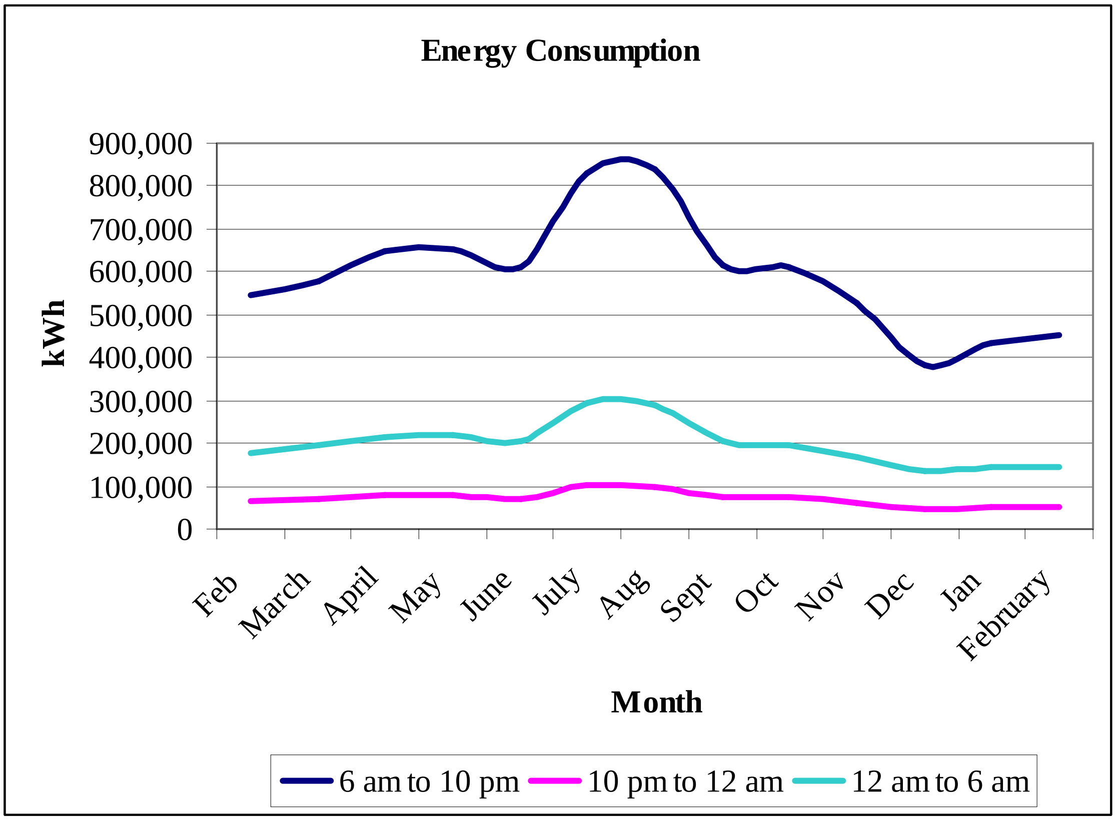

Figure 22. Galveston Monthly Energy Consumption

In the months of February, March, April, October, November, December and January the peak demand per day varied from 1300 to 1400 kW. From June to September the peak demand of each day varied from 1300 to a little over 2000 kW. Most of the time, the peak demand occurred around 4 pm. The peak demand during weekdays occurred from 12 noon to 5 pm and from 1 pm to 11 pm during weekends. During weekends the peak demand for most of the year occurred at 10 pm. In general, the lowest energy consumption during weekdays occurred from 10 pm to 5 am, most of the time between 3 and 4 am. During weekends, the lowest energy consumption occurred early morning, most of the time between 7 and 9 am. The lowest demand varied from 700 to 1000 kW during January, February, March, April, October, November and December. The lowest demand occurring from June to September varied from 700 to 1700 kW. See Figures 23 through 28 for Galveston weekdays and weekends average energy profiles.

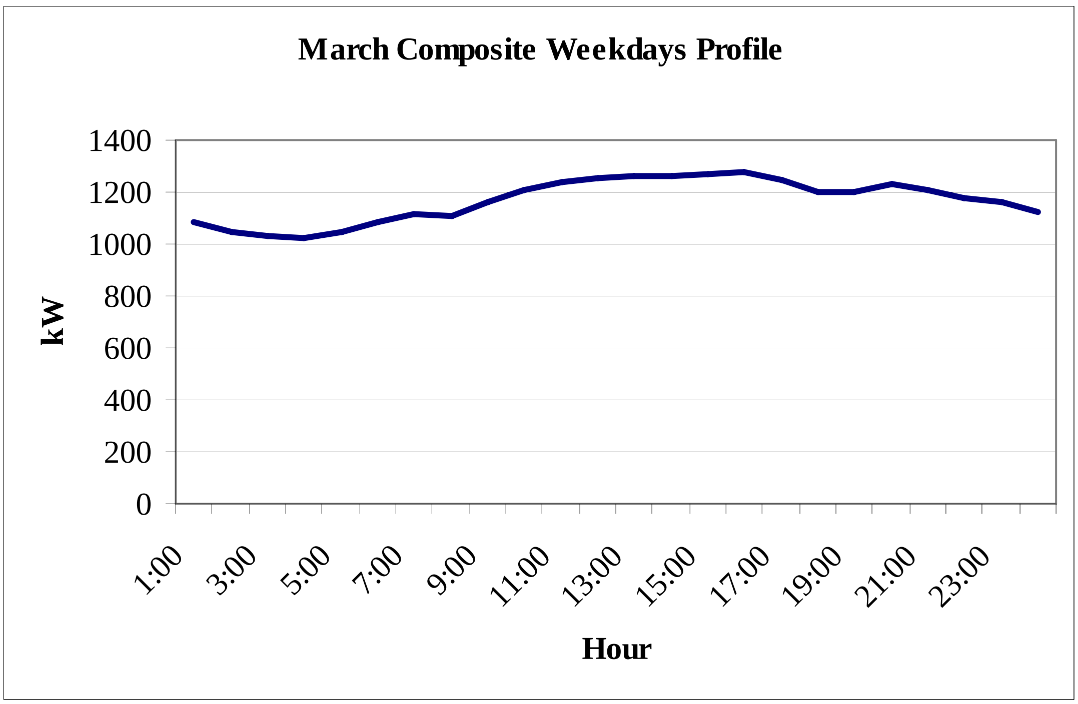

Figure 23. Galveston March Weekday Average Energy Profile

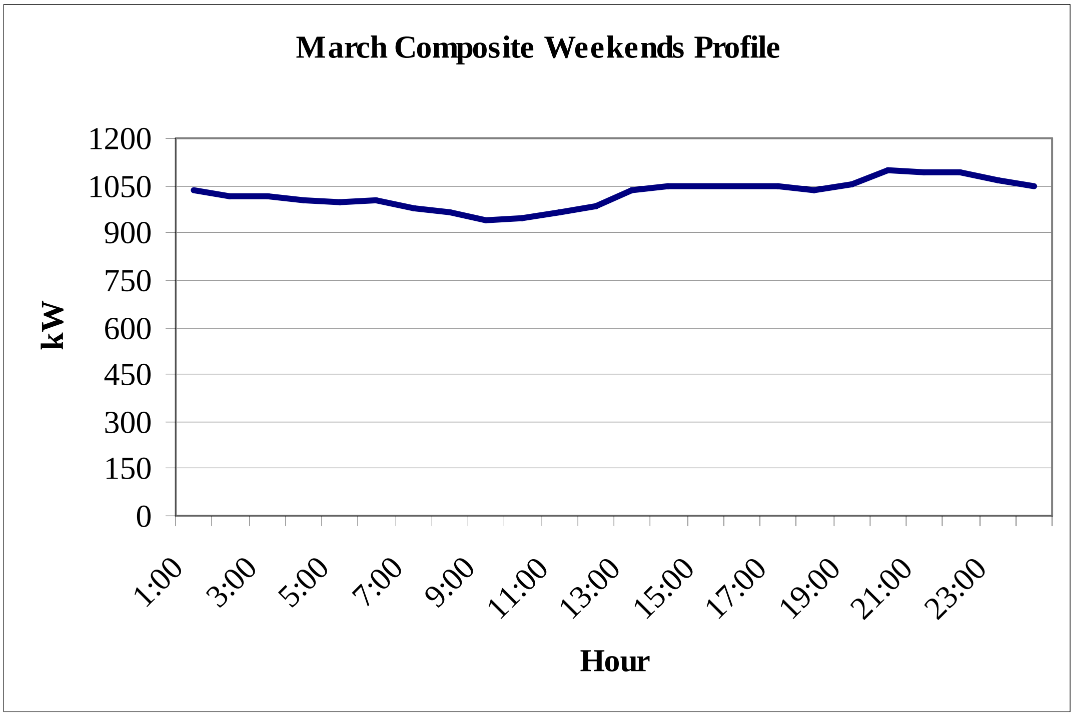

Figure 24. Galveston March Weekends Average Energy Profile

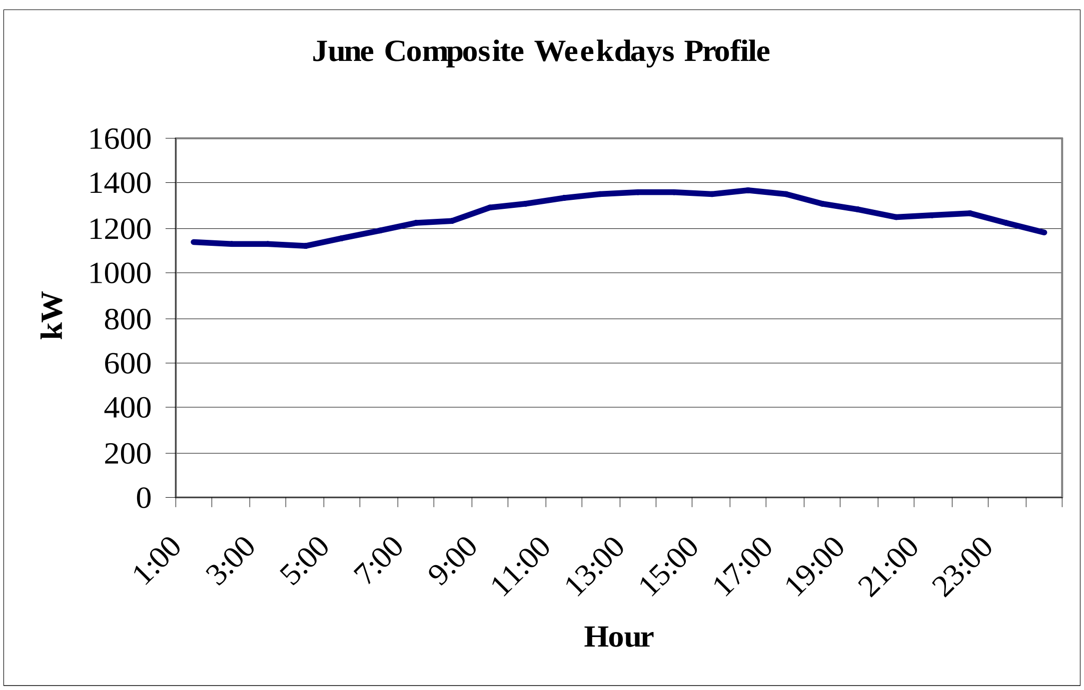

Figure 25. Galveston June Weekday Average Energy Profile

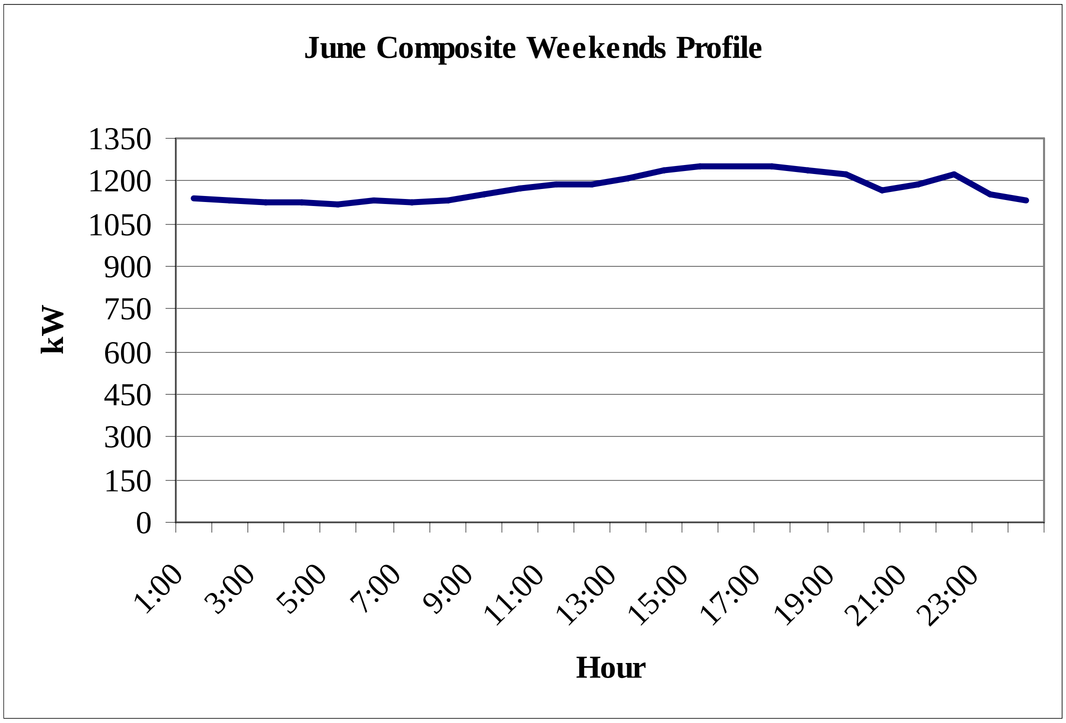

Figure 26. Galveston June Weekends Average Energy Profile

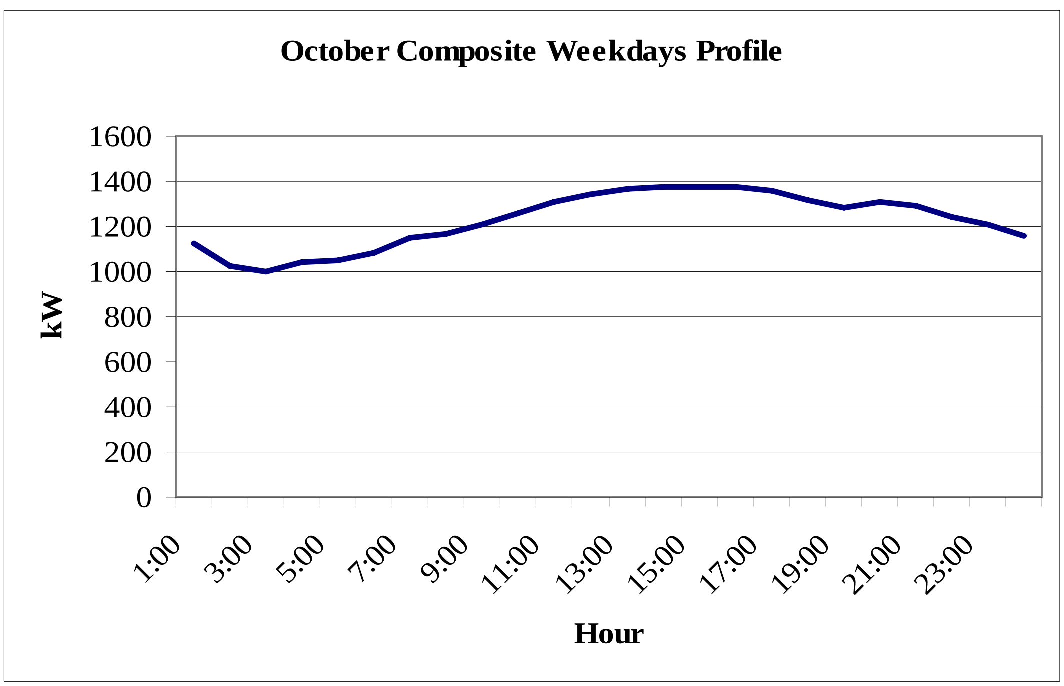

Figure 27. Galveston October Weekday Average Energy Profile

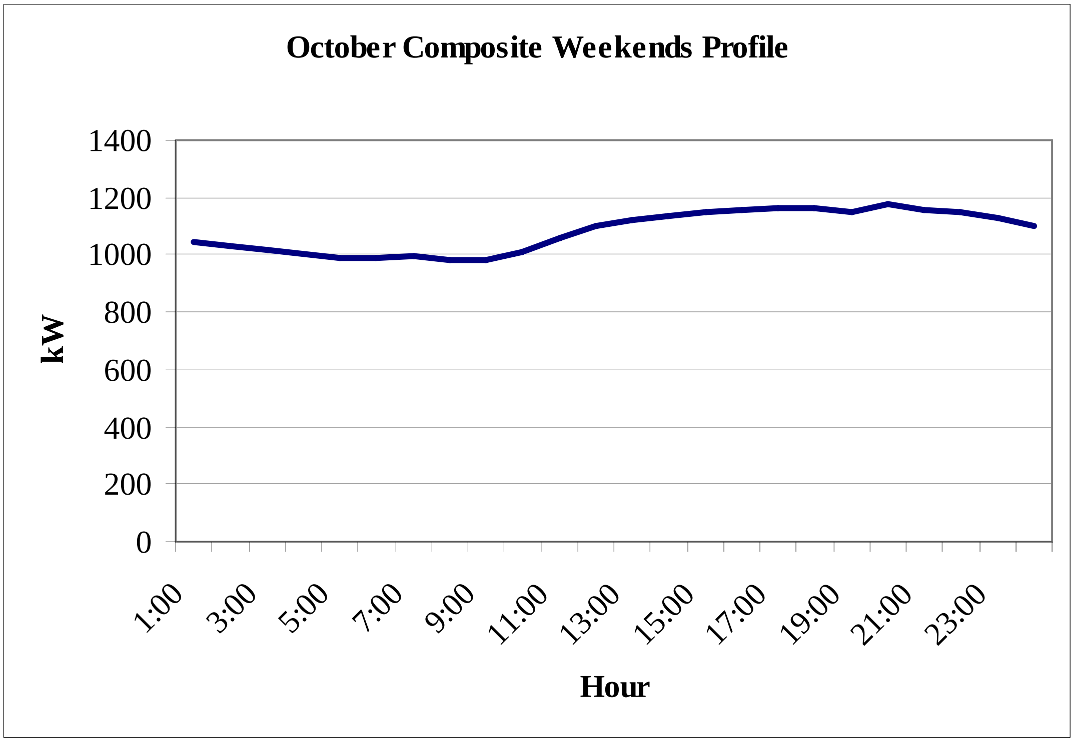

Figure 28. Galveston October Weekends Average Energy Profile

C. Texas A&M University at Kingsville

Texas A&M University in Kingsville (TAMU-Kingsville) has approximately 6,200 students, thirty-three buildings with a total gross area of 1,424,000 square feet. The thirty-three buildings include approximately seventeen academic buildings, six housing facilities, one administration building, the recreational center, and the Jernigan Library. Texas A&M at Kingsville is located in the South Zone of ERCOT, and AEP (American Electric Power) provides the transmission and distribution services.

The Kingsville campus consumed around 34,719,189 kWh from March 2005 to February 2006. The greatest monthly energy consumption took place in September with

3,398,880 kWh followed by August with 3,393,616 kWh. The lowest monthly energy consumption took place in February 2006 with 1,613,146 kWh. See Table 8.

Table 8. Kingsville Monthly Energy Consumption

Kingsville		
Total Monthly Energy Consumption (kWh)	**Mar-05**	2,787,614.16
	Apr-05	2,801,443.44
	May-05	2,845,797.12
	Jun-05	3,131,731.92
	Jul-05	3,295,945.68
	Aug-05	3,393,615.84
	Sep-05	3,398,880.00
	Oct-05	3,256,367.04
	Nov-05	2,814,250.56
	Dec-05	2,601,576.00
	Jan-06	2,778,820.80
	Feb-06	1,613,146.56
TOTAL		34,719,189.12

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 29 for an average of energy consumption for these periods for different months. From the 69% of energy consumed from 6 am to 10 pm, 17% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1st to August 31st, 2005 this campus consumed 52% of its total load during on-peak hours and 48% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 42% of the

total energy during peak periods and 58% during off-peak times from September 1, 2005 to February 28, 2006.

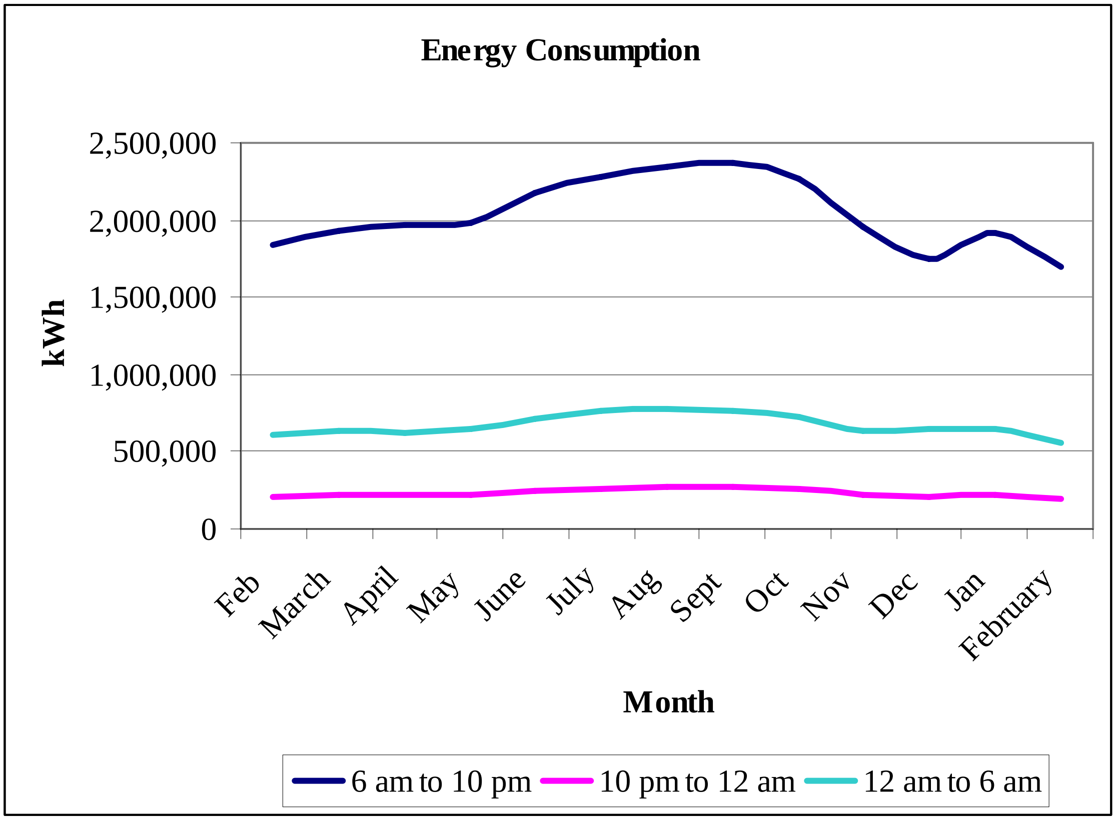

Figure 29. Kingsville Monthly Energy Consumption

In the months of February and March the peak demand during weekdays varied from 3900 to 4700 kW. In April and May the peak demand varied from 4400 kW to a little over 5100 kW. From June to September the peak demand varied from 4800 kW to 6000 kW. During October and November the peak demand varied from 3600 kW to 5400 kW. In December the peak demand varied from 3400 to 4900 kW. The peak demand during weekdays generally occurred from 11 am to 4 pm and from 2 pm to 10 pm during the weekends. Most of the time, the peak demand occurred around noon. In general, the lowest consumption of energy during weekdays occurred early morning, most of the time from 3 am to 4 am. During the weekends, the lowest energy consumption occurred early morning, most of the time around 8 am. The lowest energy consumption during weekdays varied from 2000 to 3400 kW during January, February, March, and December. See Figures 30 through 35 for Kingsville weekdays and weekends average energy profiles.

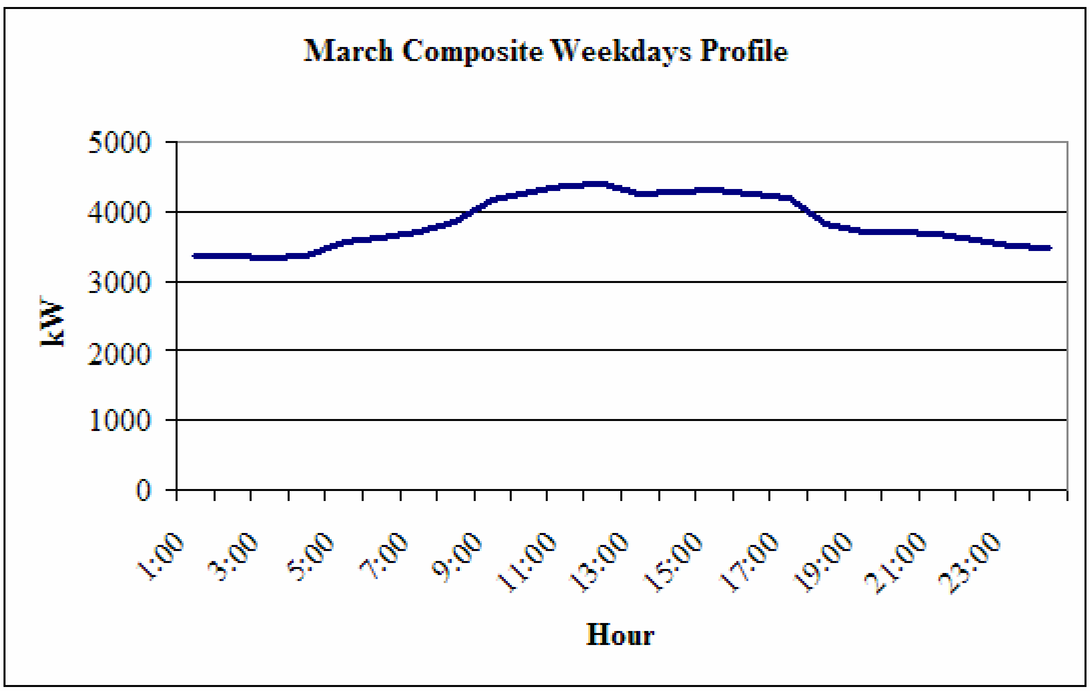

Figure 30. Kingsville March Weekday Average Energy Profile

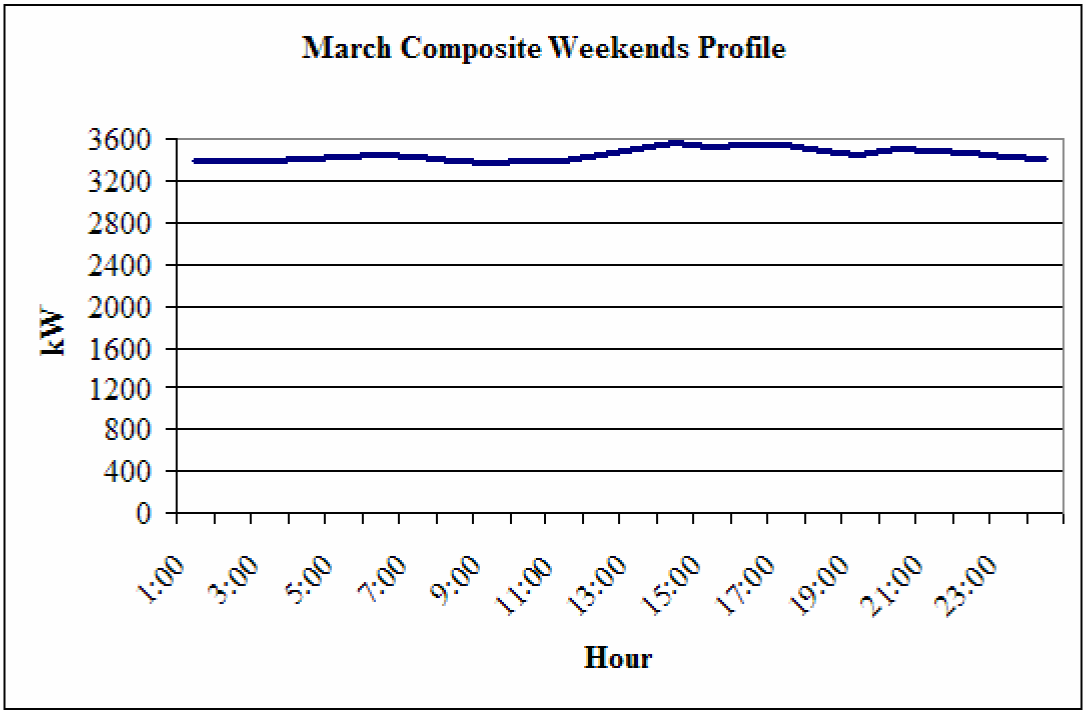

Figure 31. Kingsville March Weekend Average Energy Profile

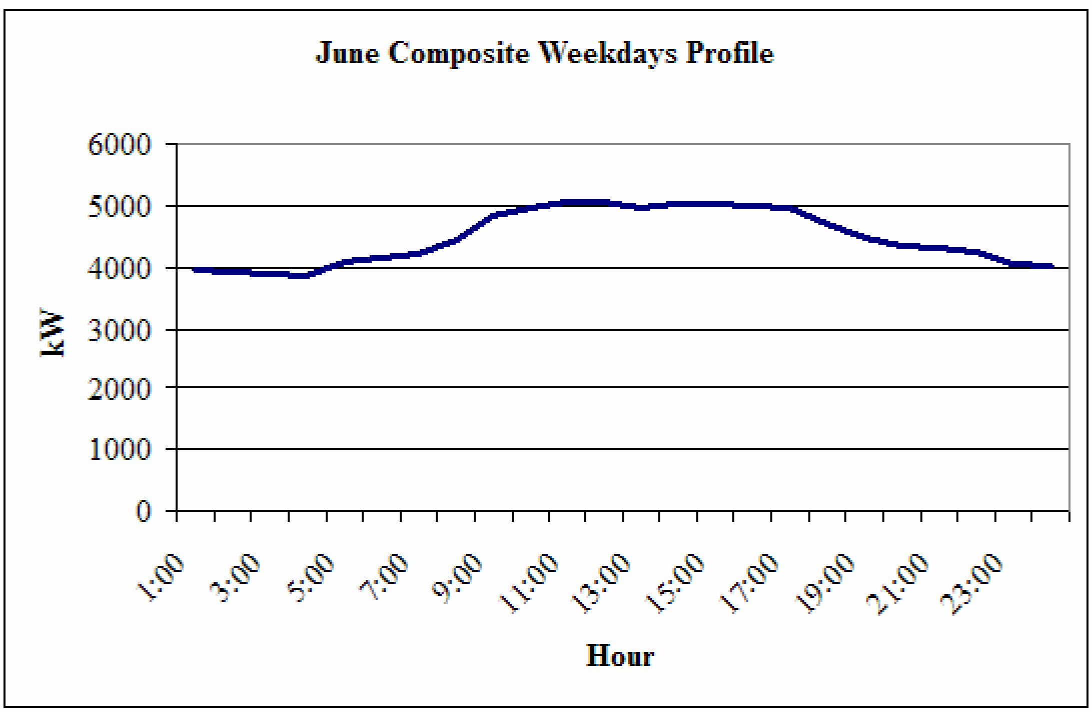

Figure 32. Kingsville June Weekday Average Energy Profile

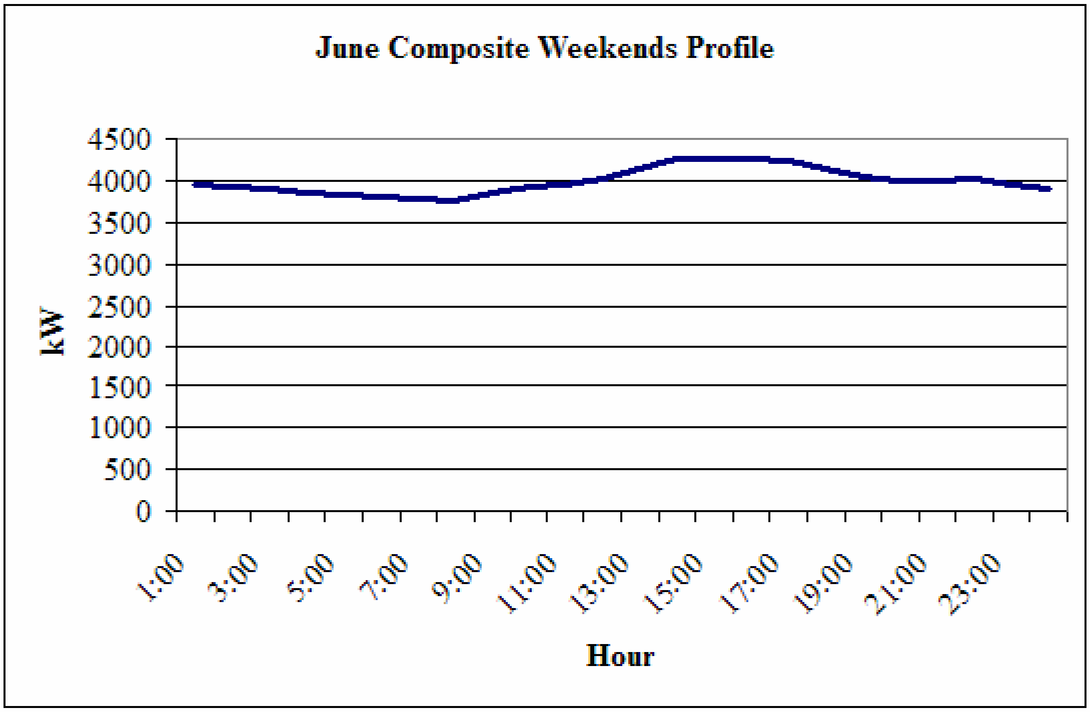

Figure 33. Kingsville June Weekend Average Energy Profile

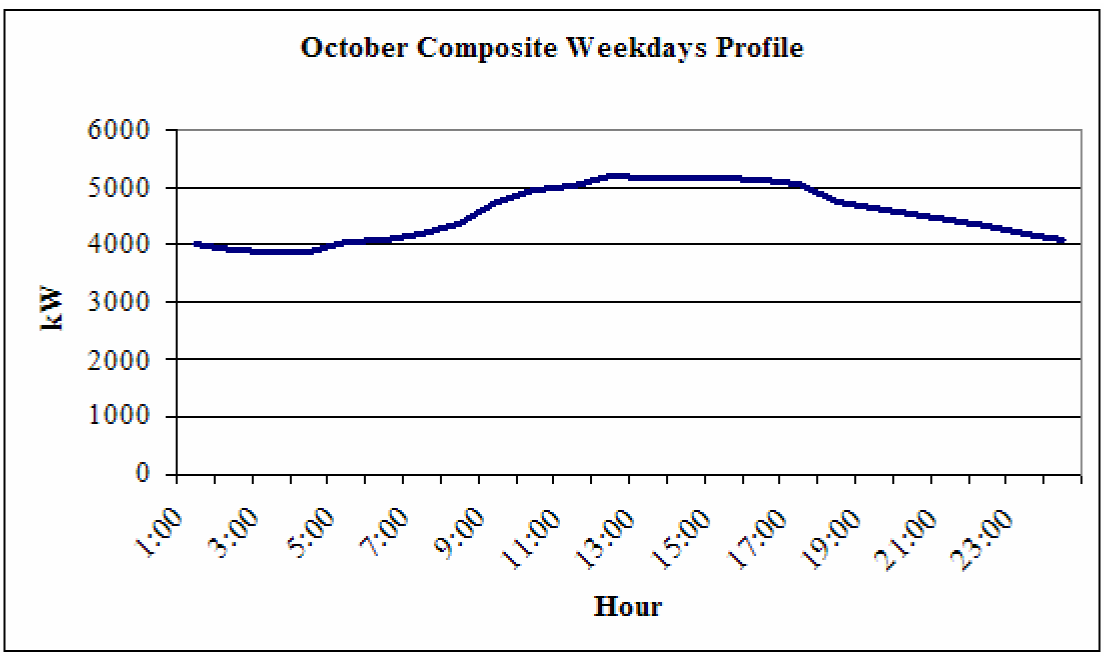

Figure 34. Kingsville October Weekday Average Energy Profile

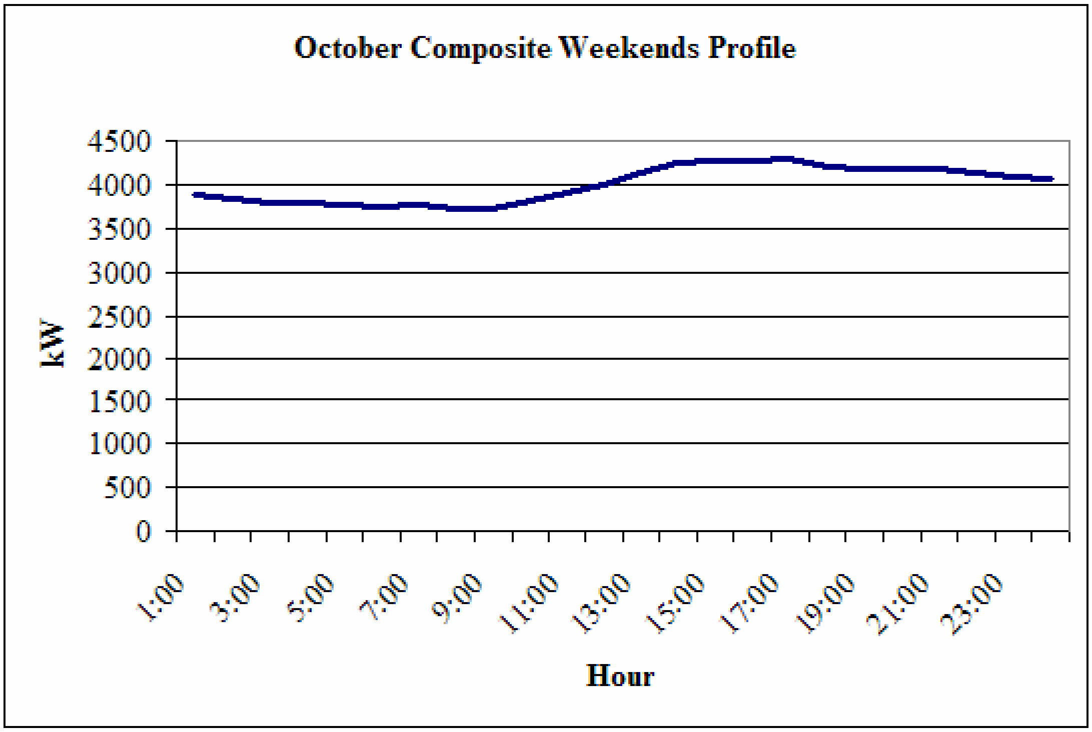

Figure 35. Kingsville October Weekend Average Energy Profile

D. Texas A&M International University

Texas A&M International University (TAMU-Laredo) is a 300 acre-campus in Laredo and has approximately 4,400 students, 13 buildings, one housing facility, and the Sue and Radcliffe Killam library composing a total gross area of approximately 760,000 square feet. The Texas A&M campus in Laredo is located in the South Zone of ERCOT, and AEP (American Electric Power) provides the transmission and distribution services.

The Laredo campus consumed 19,320,856 kWh from March 1, 2005 to February 28, 2006. August and September consumed the most energy compared during the year, with the greatest monthly energy consumption taking place in August, 2005 with 1,994,188 kWh. The lowest monthly energy consumption took place in February 2006 with 1,263,784 kWh. See Table 9.

Table 9. Laredo Monthly Energy Consumption

Laredo		
Total Monthly Energy Consumption (kWh)	**Mar-05**	1,370,944.32
	Apr-05	1,540,483.20
	May-05	1,698,513.60
	Jun-05	1,845,220.80
	Jul-05	1,875,452.16
	Aug-05	1,994,188.80
	Sep-05	1,903,214.40
	Oct-05	1,745,563.20
	Nov-05	1,491,027.84
	Dec-05	1,269,142.08
	Jan-06	1,323,321.60
	Feb-06	1,263,784.32
TOTAL		19,320,856.32

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 71% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 21% from midnight to 6 am. See Figure 36 for an average of energy consumption for these periods for different months. From the 71% of energy consumed from 6 am to 10 pm, 18% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 53% of its total load during on-peak hours and 47% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 43% of the

total energy during peak periods and 57% during off-peak times from September 1, 2005 to February 28, 2006.

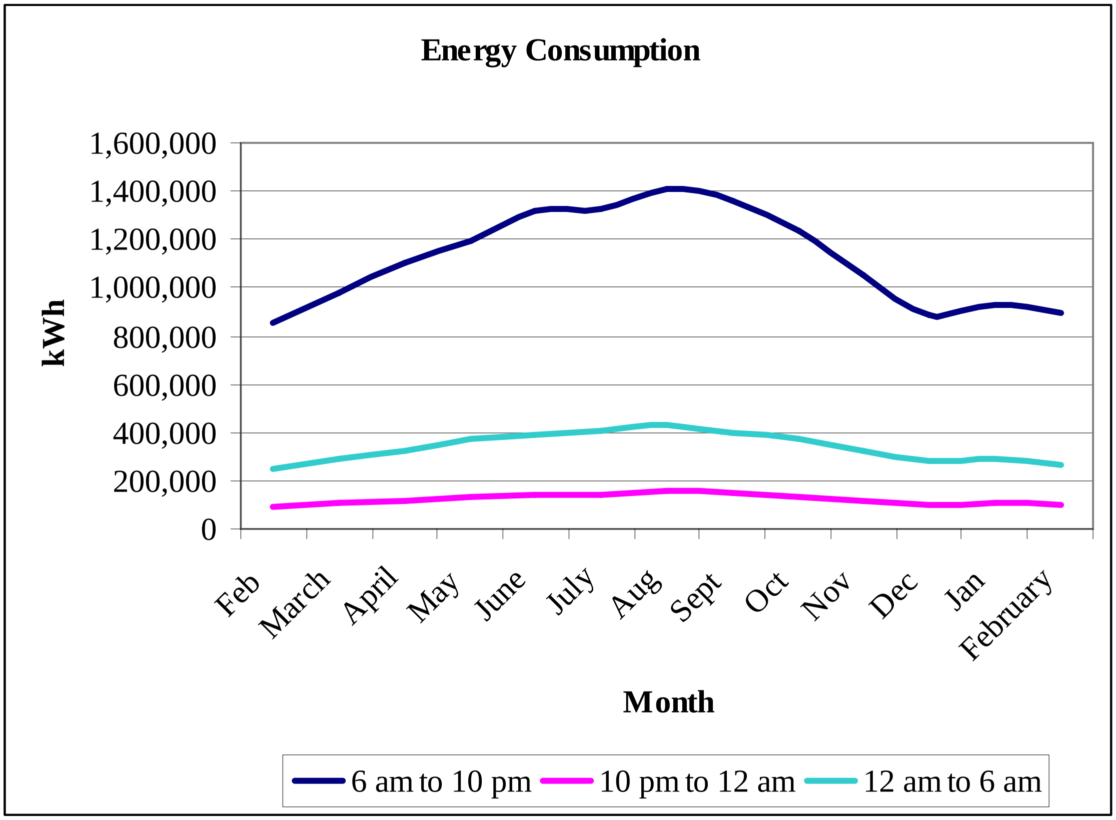

Figure 36. Laredo Monthly Energy Consumption

In the months of February and March the peak demand during weekdays varied from 1900 to 2600 kW. From April to May the peak demand varied from 2300 to 3100 kW; from June to October the peak demand varied from 2700 kW to a little over 3300 kW. From November to December the peak demand varied from 1600 kW to 2300 kW. Most of the time, the peak demand occurred in the period from 4 pm to 5 pm.

In general, the peak demand during weekdays occurred between noon and 5 pm and from noon to 9 pm during the weekends. In general, the lowest consumption of energy during weekdays and weekends occurred early morning, most of the time around 5 am. The lowest energy consumption ranged from 1300 to 2000 kW during January, February, March, November, and December. See Figures 37 through 42 for Laredo weekdays and weekends average energy profiles.

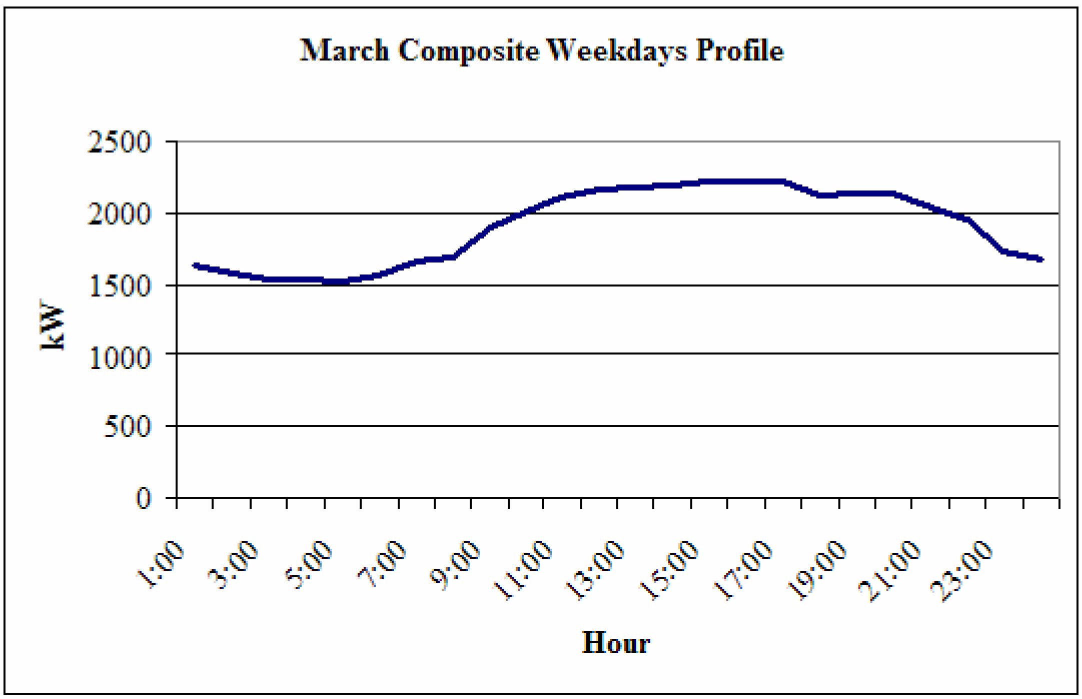

Figure 37. Laredo March Weekday Average Energy Profile

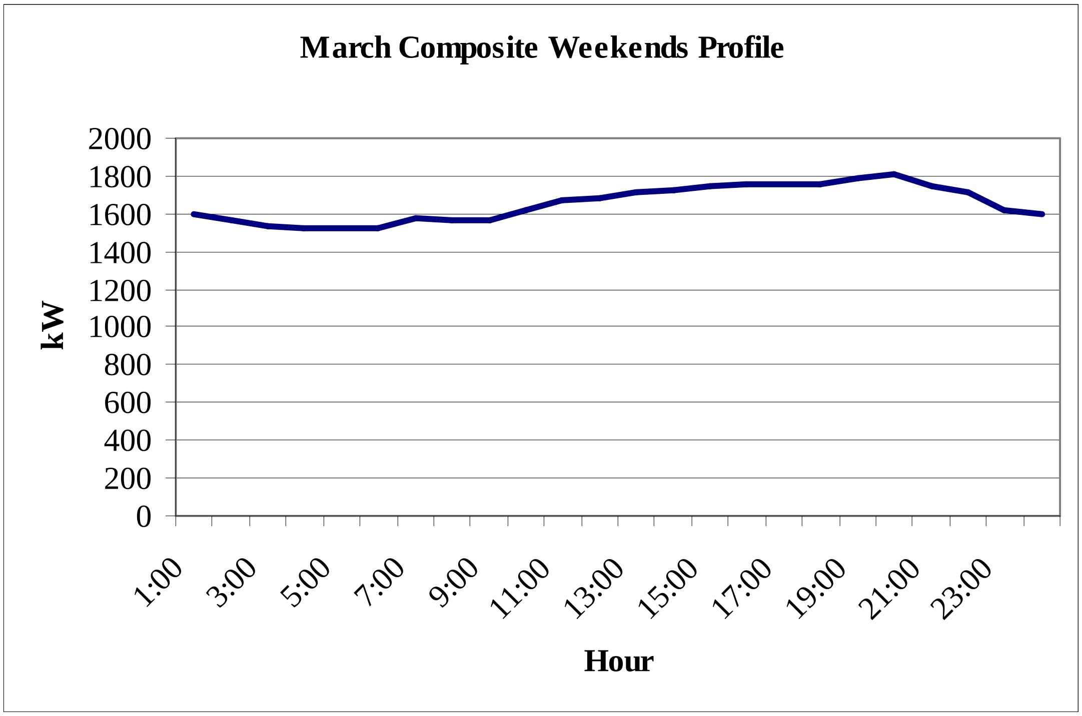

Figure 38. Laredo March Weekend Average Energy Profile

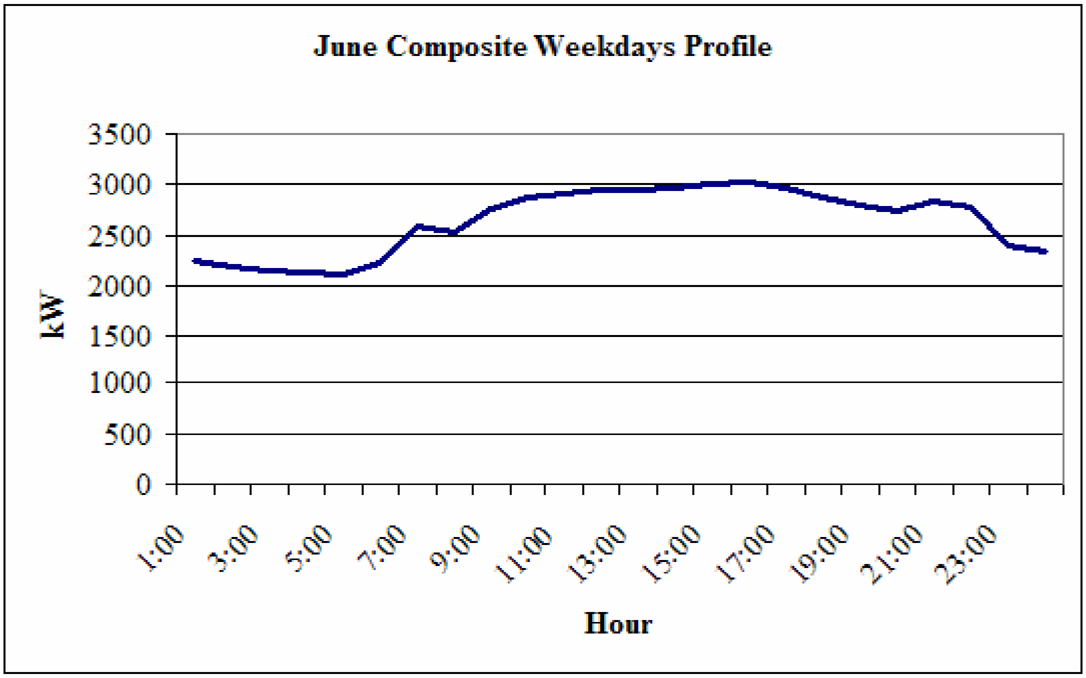

Figure 39. Laredo June Weekday Average Energy Profile

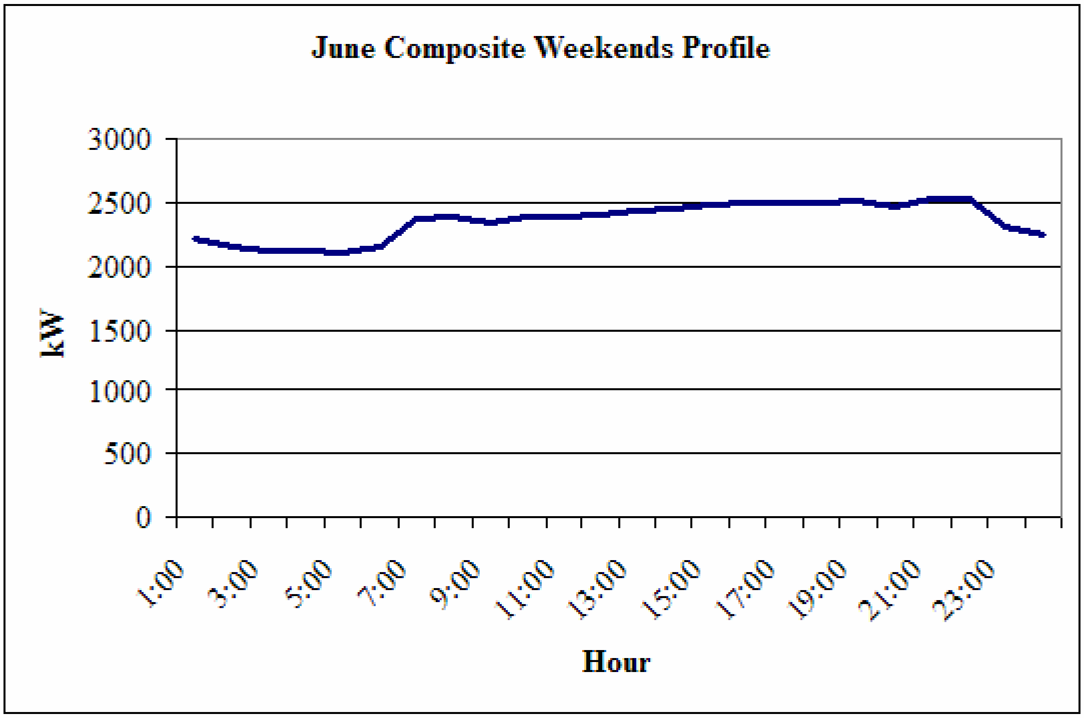

Figure 40. Laredo June Weekend Average Energy Profile

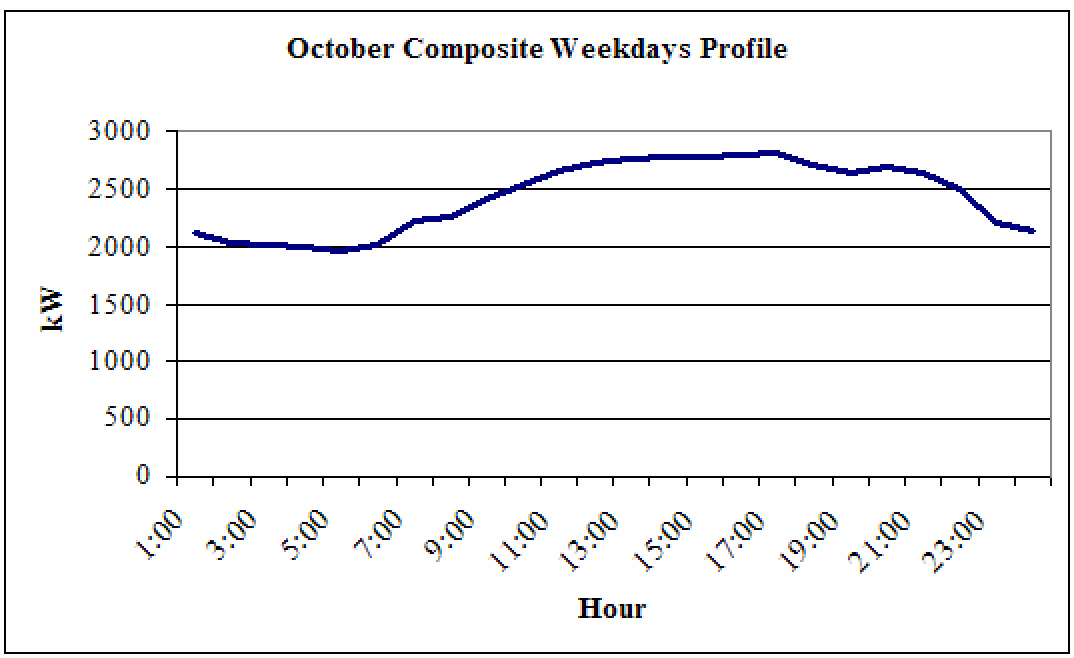

Figure 41. Laredo October Weekday Average Energy Profile

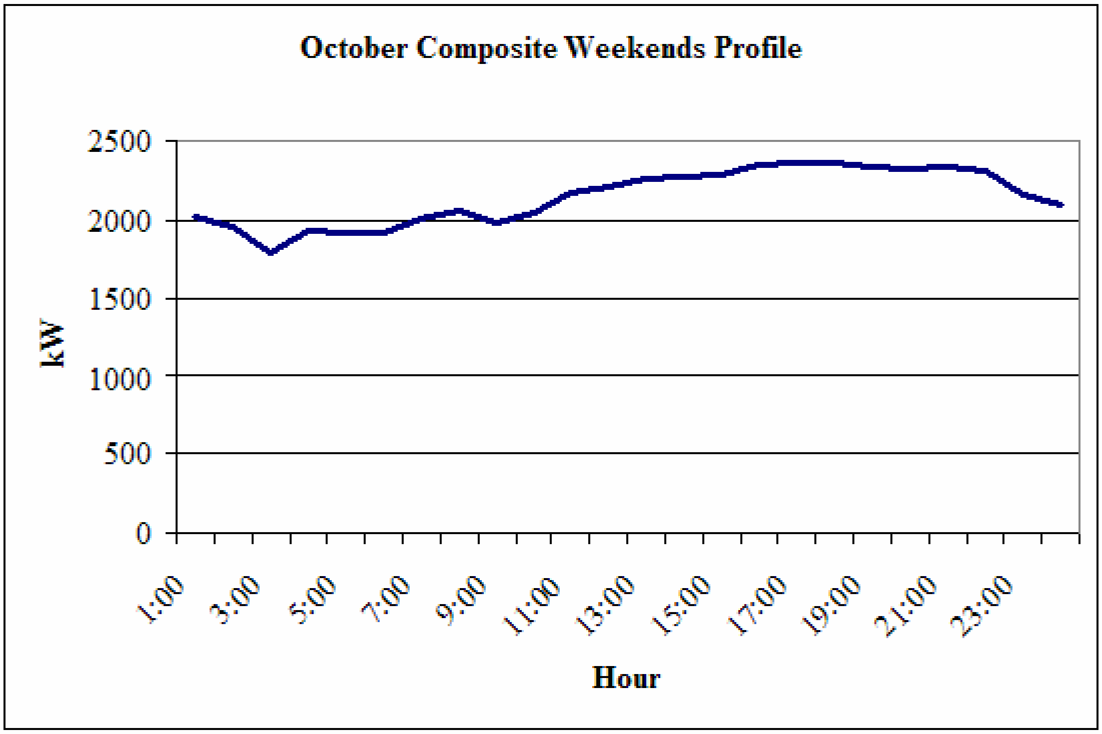

Figure 42. Laredo October Weekend Average Energy Profile

E. Texas A&M University in Commerce

Texas A&M University in Commerce (TAMU-Commerce) covers a total of 1,883 acres in Commerce. The main campus is 150 acres, and it has approximately 87 buildings. The college farm campus is 1,743 acres, and it has approximately 25 buildings. Texas A&M-Commerce has approximately 7,400 students. It is located in the Northeast Zone of ERCOT, and TXU Electric Delivery provides the transmission and distribution services.

There are two major accounts for this campus. One of the IDR meters, referred to as Commerce 7 (Co 7), located on the Commerce campus recorded an energy consumption of 24,539,767 kWh from March 2005 to February 2006. August and September consumed the most energy compared to the rest of the year and the greatest monthly energy consumption was in August with 2,498,865 kWh. The lowest monthly energy consumption took place in February 2006 with 1,646,233 kWh. See Table 10.

Table 10. Commerce-7 Monthly Consumption

Commerce 7		
Total Monthly Energy Consumption (kWh)	**Mar-05**	1,752,901.56
	Apr-05	1,869,630.12
	May-05	2,054,309.04
	Jun-05	2,369,233.80
	Jul-05	2,310,699.96
	Aug-05	2,498,865.12
	Sep-05	2,478,015.72
	Oct-05	2,223,261.00
	Nov-05	1,911,742.56
	Dec-05	1,709,313.84
	Jan-06	1,715,561.64
	Feb-06	1,646,233.20
TOTAL		24,539,767.56

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 76% was consumed from the hours of 6 am to 10 pm, 6% from 10 pm to midnight, and 18% from midnight to 6 am. See Figure 43 for an average of energy consumption for these periods for different months. From the 76% of energy consumed from 6 am to 10 pm, 18% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 58% of its total load during on-peak hours and 42% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 48% of the

total energy during peak periods and 52% during off-peak times from September 1, 2005 to February 28, 2006.

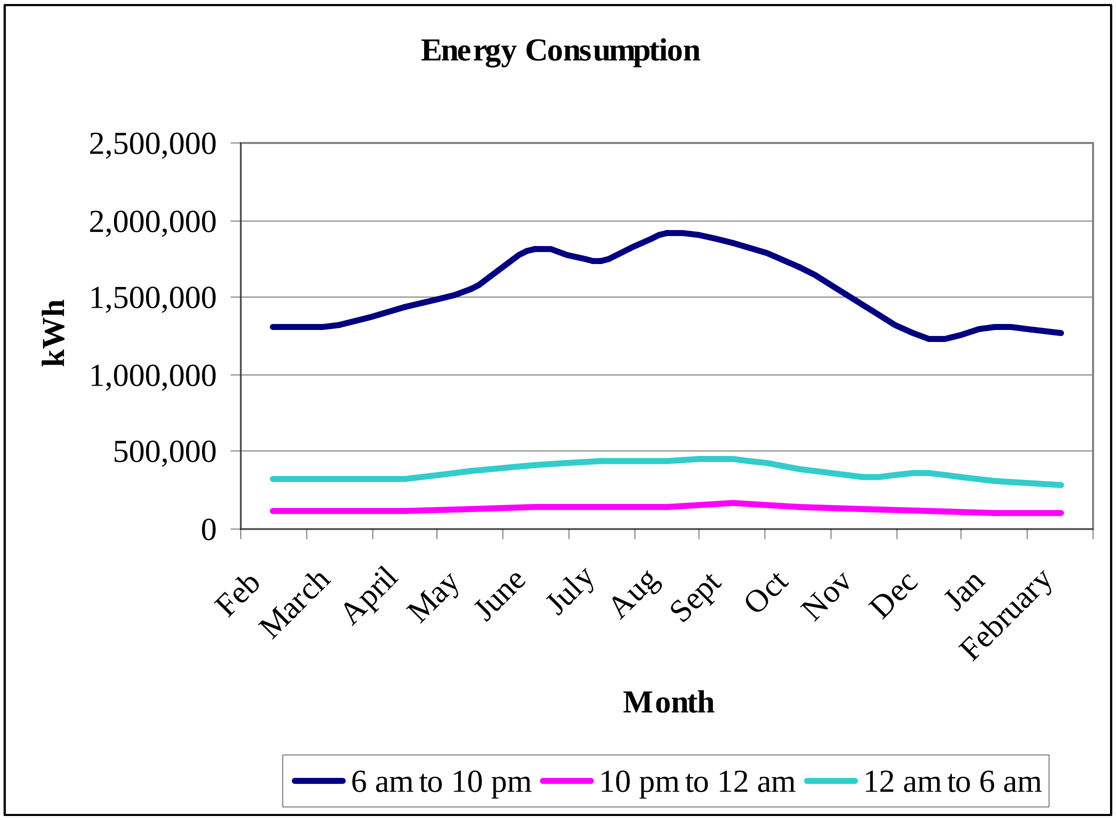

Figure 43. Commerce-7 Monthly Energy Consumption

In the months of February and March the peak demand during weekdays varied from 3100 to 3500 kW. In April and May the peak demand varied from 3200 to 4200 kW; from June to October the peak demand varied from 3500 kW to a little over 5000 kW; from November to December the peak demand varied from 1600 kW to 4800 kW. Most of the time, the peak demand occurred in the period from noon to 3 pm.

In general, the peak demand during weekdays occurred from 12 pm to 5 pm and from 11 pm to 8 pm during weekends. The lowest consumption of energy during weekdays and weekends occurred early morning, most of the time from 3 to 4 am. The lowest energy consumption was around 1400 to 1700 kW during January, February, March, November, and December. See Figures 44 through 49 for Commerce-7 weekdays and weekends average energy profiles.

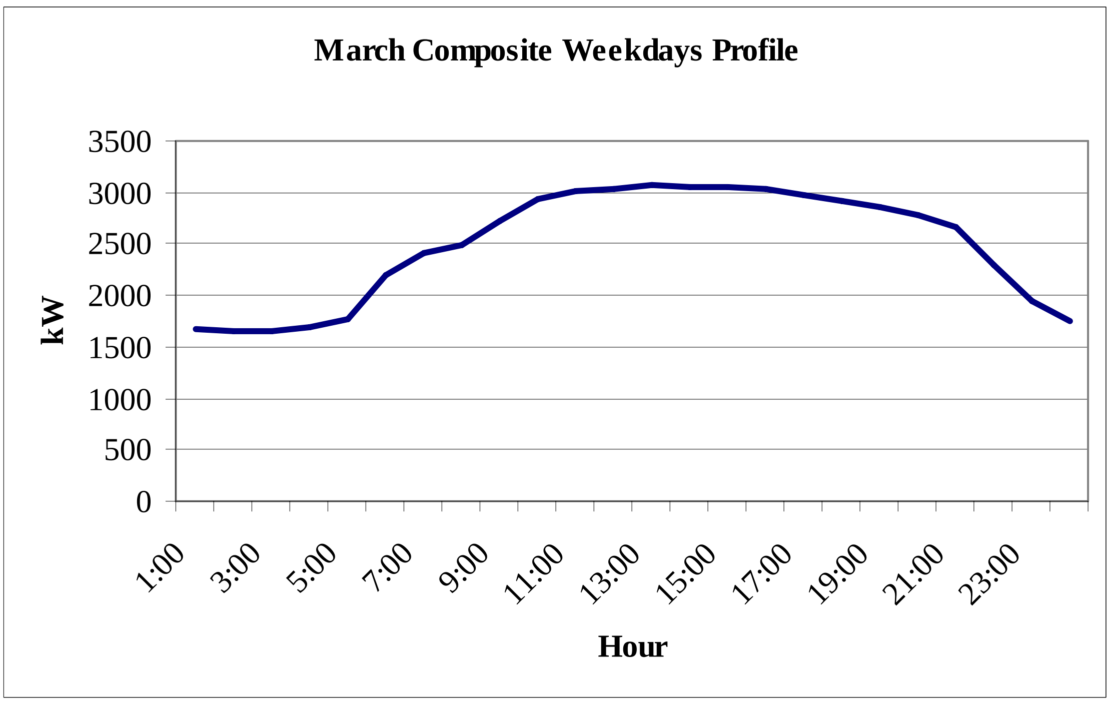

Figure 44. Commerce-7 March Weekday Average Energy Profile

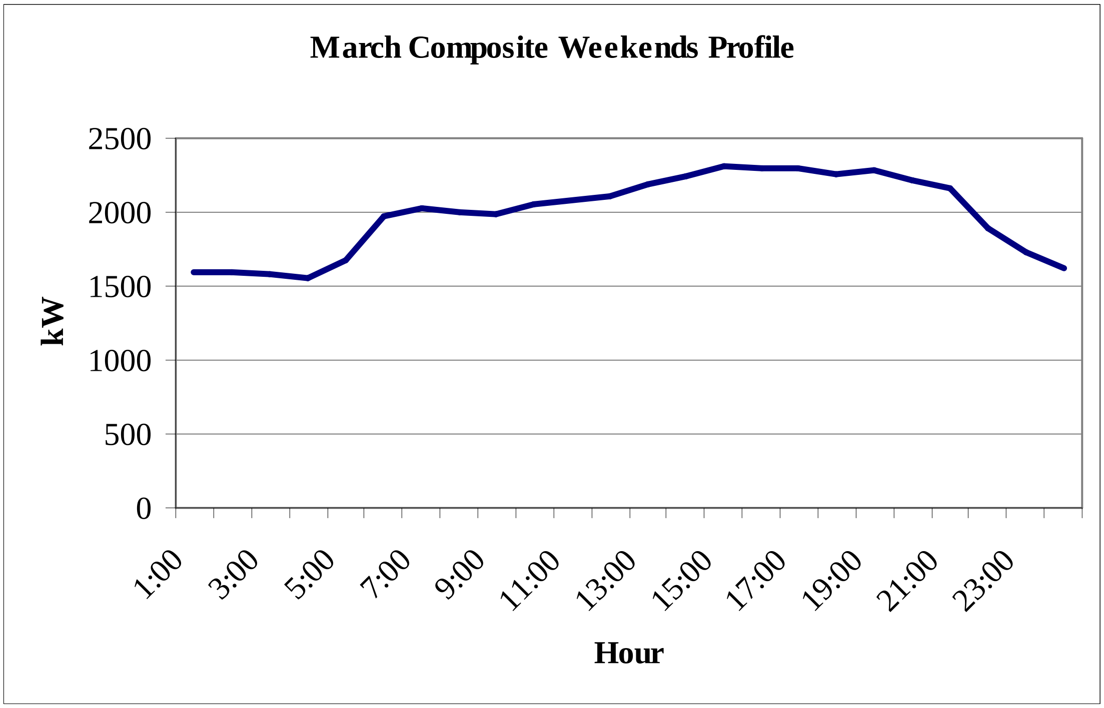

Figure 45. Commerce-7 March Weekend Average Energy Profile

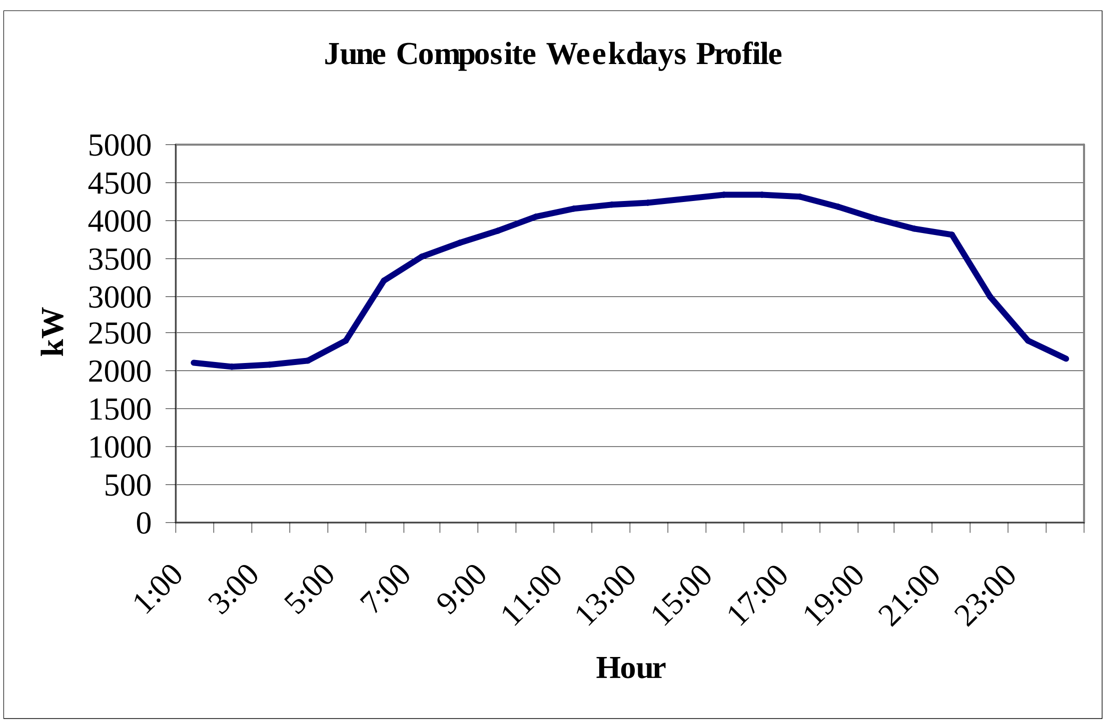

Figure 46. Commerce-7 June Weekday Average Energy Profile

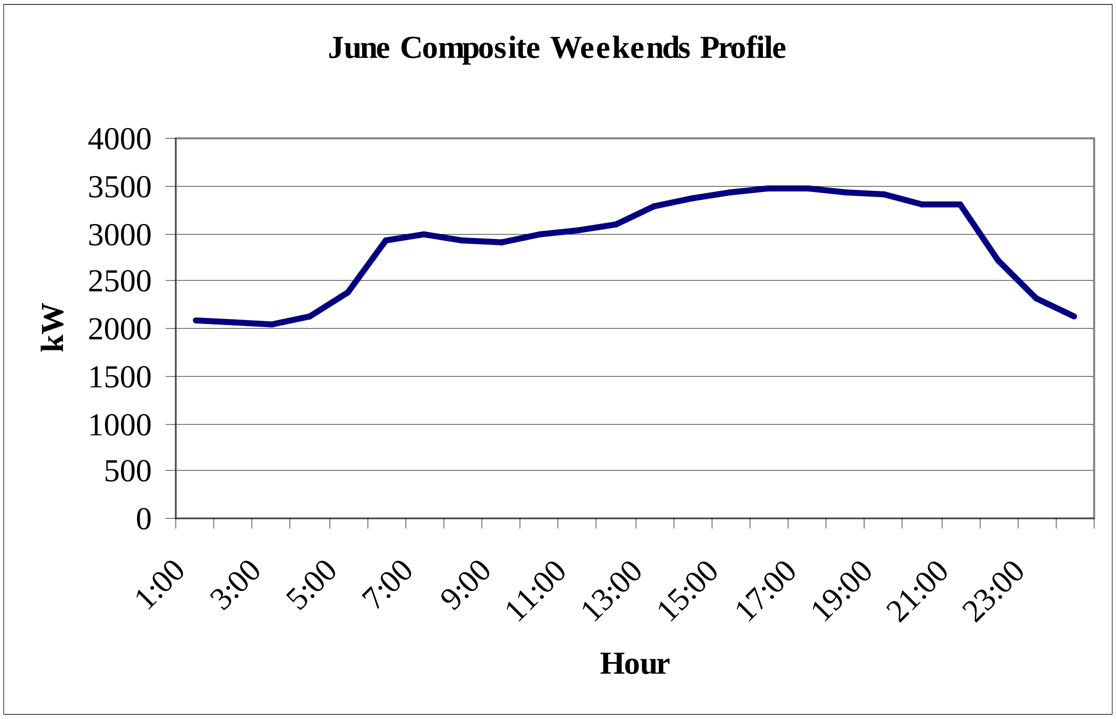

Figure 47. Commerce-7 June Weekend Average Energy Profile

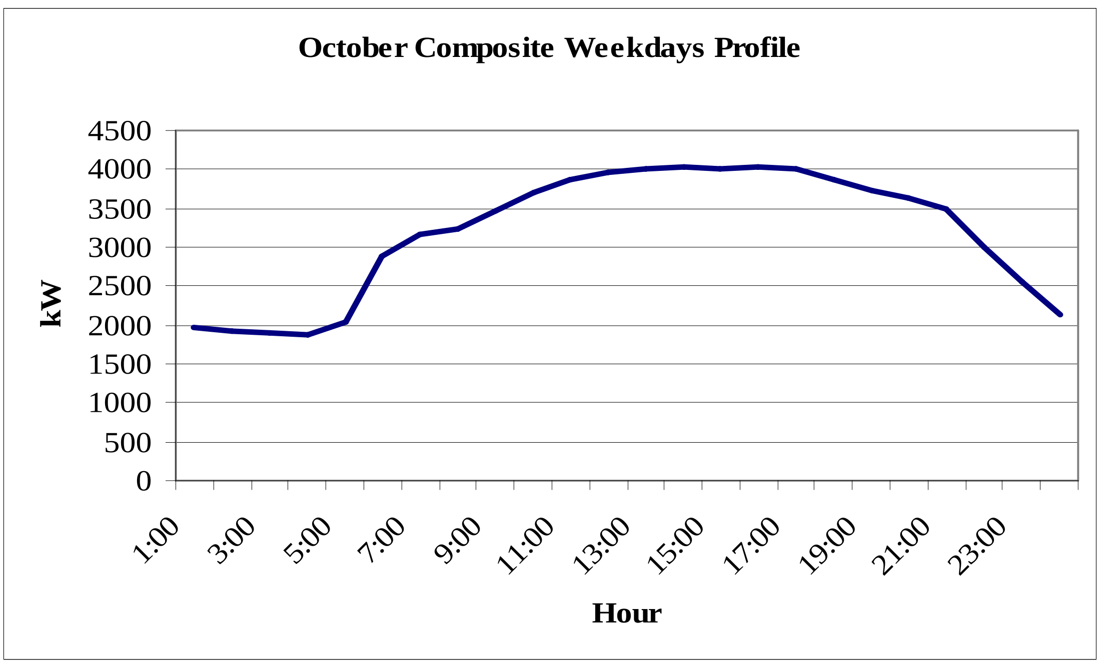

Figure 48. Commerce-7 October Weekday Average Energy Profile

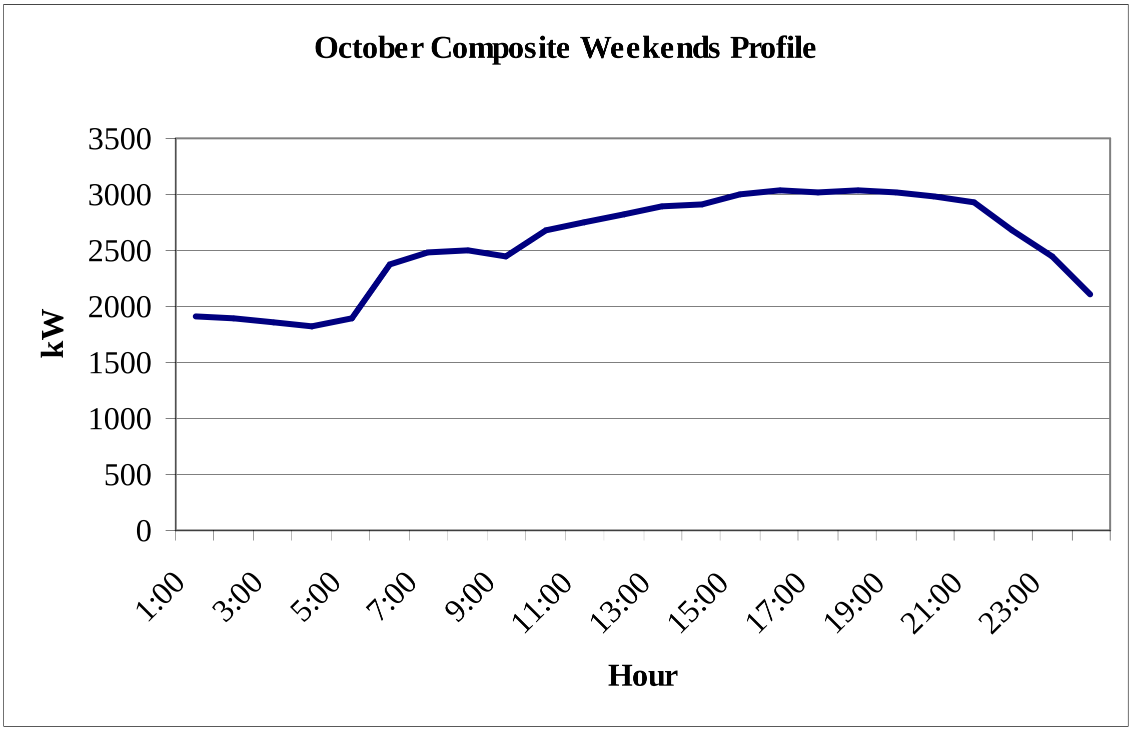

Figure 49. Commerce-7 October Weekend Average Energy Profile

The second IDR meter on Commerce, referred to as Commerce 8 (Co 8), recorded an energy consumption of 5,580,115 kWh from March 2005 to February 2006. The greatest monthly energy consumption was in August with 599,176 kWh. The lowest monthly energy consumption took place in January 2006 with 351,722 kWh. See Table 11.

Table 11. Commerce-8 Monthly Energy Consumption

Commerce 8		
Total Monthly Energy Consumption (kWh)	**Mar-05**	364,312.08
	Apr-05	393,561.18
	May-05	463,926.42
	Jun-05	566,263.44
	Jul-05	596,176.20
	Aug-05	599,314.46
	Sep-05	517,710.96
	Oct-05	527,547.60
	Nov-05	431,216.46
	Dec-05	382,823.28
	Jan-06	351,722.52
	Feb-06	385,540.56
TOTAL		5,580,115.16

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 67% was consumed from the hours of 6 am to 10 pm, 9.5% from 10 pm to midnight, and 23.5% from midnight to 6 am. See Figure 50 for an average of energy consumption for these periods for different months. From the 67% of energy consumed from 6 am to 10 pm, 18% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 49% of its total load during on-peak hours and 51% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 39% of the total energy during peak periods and 61% during off-peak times from September 1, 2005 to February 28, 2006.

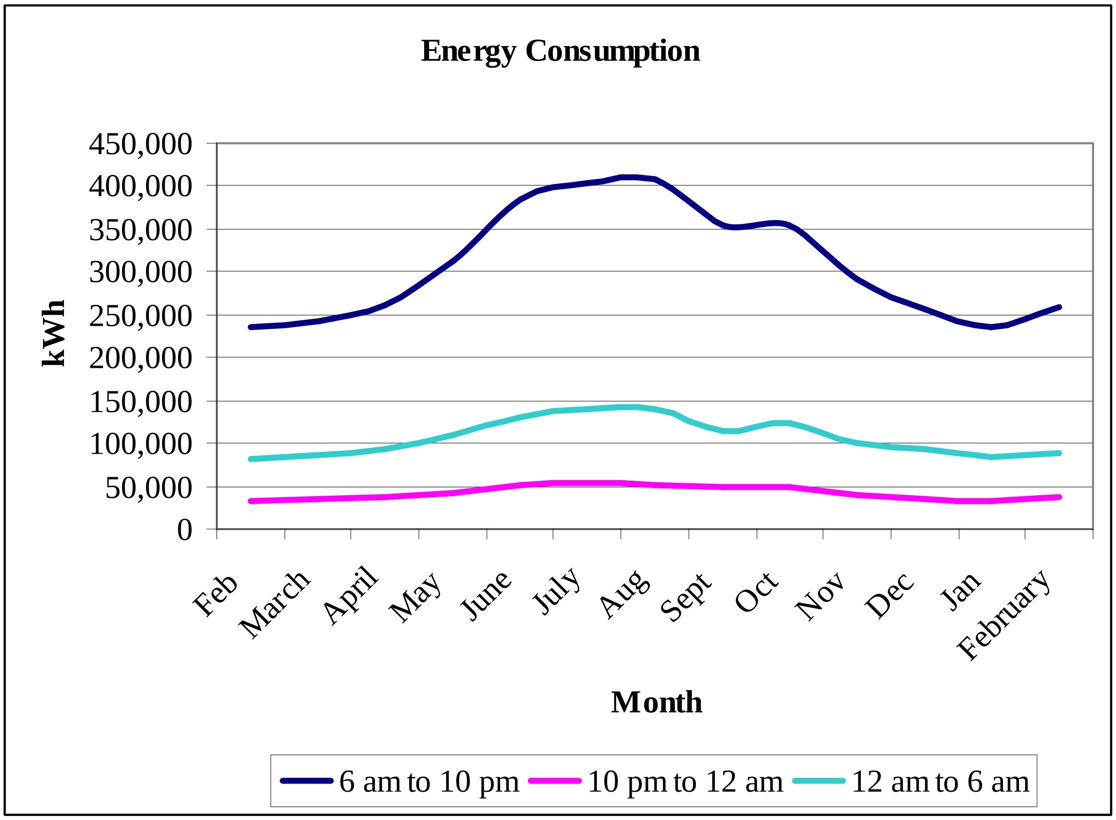

Figure 50. Commerce-8 Monthly Energy Consumption

In the months of February and March the peak demand during weekdays varied from 500 to 700 kW; from April to May the peak demand varied from 500 to 800 kW. From June to October the peak demand varied from 700 kW to a little over 1100 kW; from November to December the peak demand varied from 400 kW to 700 kW. Most of the time, the peak demand occurred from 9 pm to 10 pm. Due to the profile of energy consumption for this meter, it is believed that this meter includes the energy consumption of some of the dormitories in Commerce.

In general, the peak demand during weekdays occurred from 5 pm to 11 pm and from 6 pm to 11 pm during the weekends. The lowest consumption of energy during weekdays occurred early morning, most of the time from 6 am to 8 am. During the weekends, the lowest energy consumption occurred early morning, most of the time from 8 am to 9 am. The lowest energy consumption varied from 310 to 590 kW during January, February, March, November, and December. See Figures 51 through 56 for Commerce-8 weekdays and weekends average energy profiles.

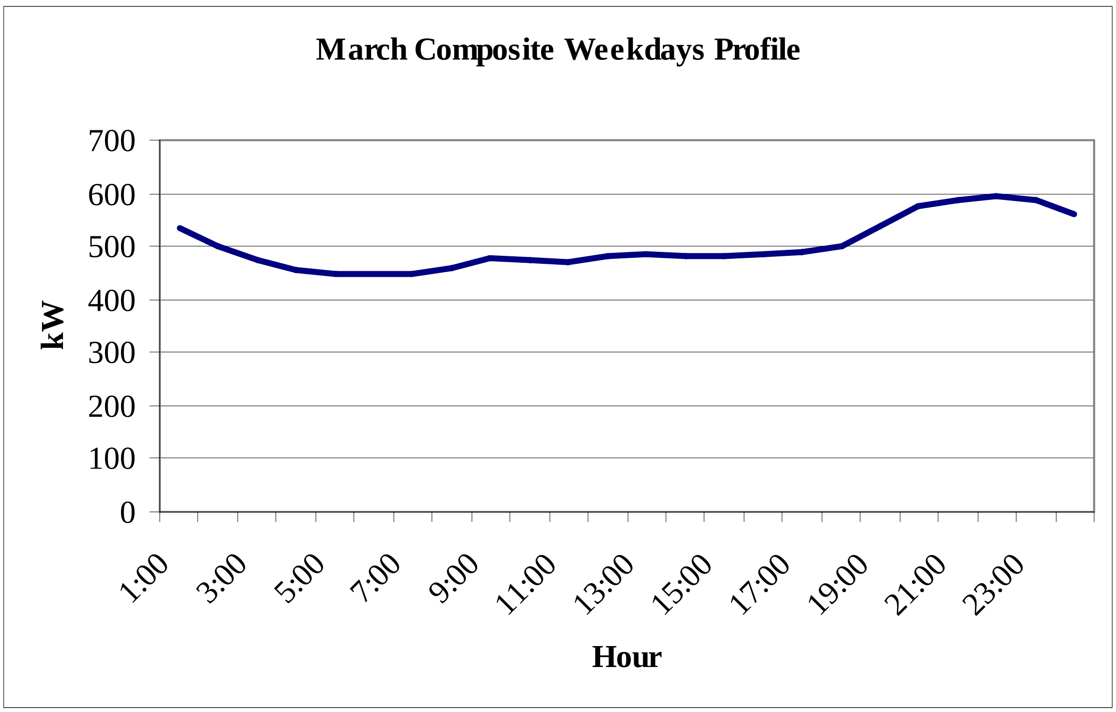

Figure 51. Commerce-8 March Weekday Average Energy Profile

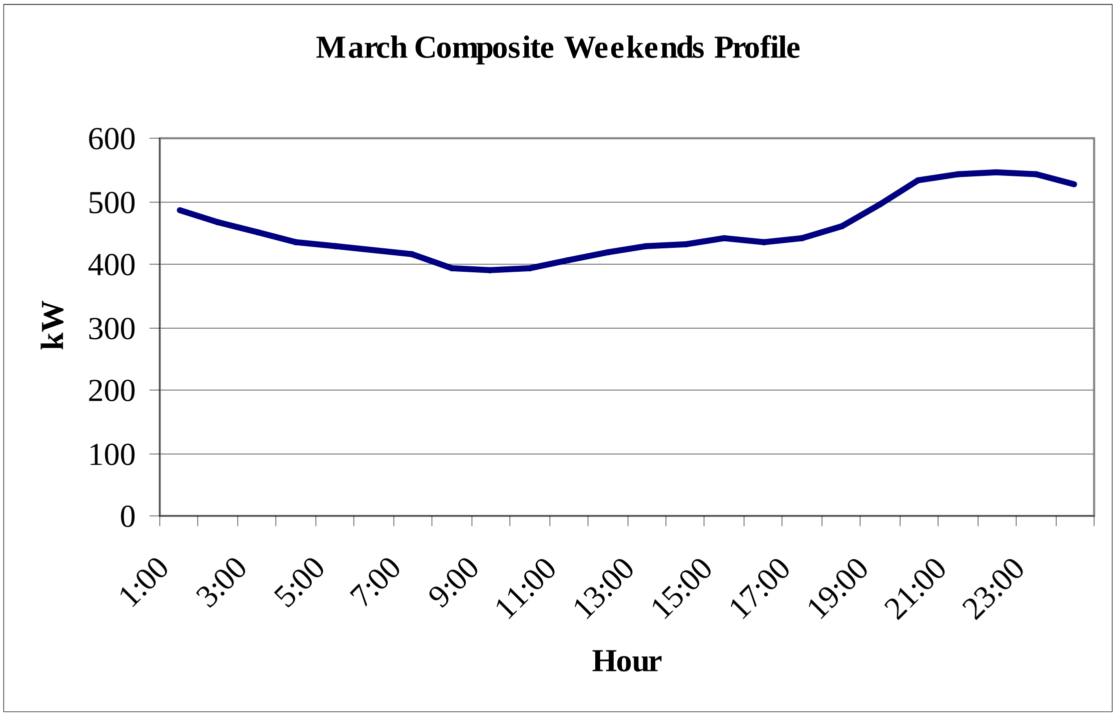

Figure 52. Commerce-8 March Weekend Average Energy Profile

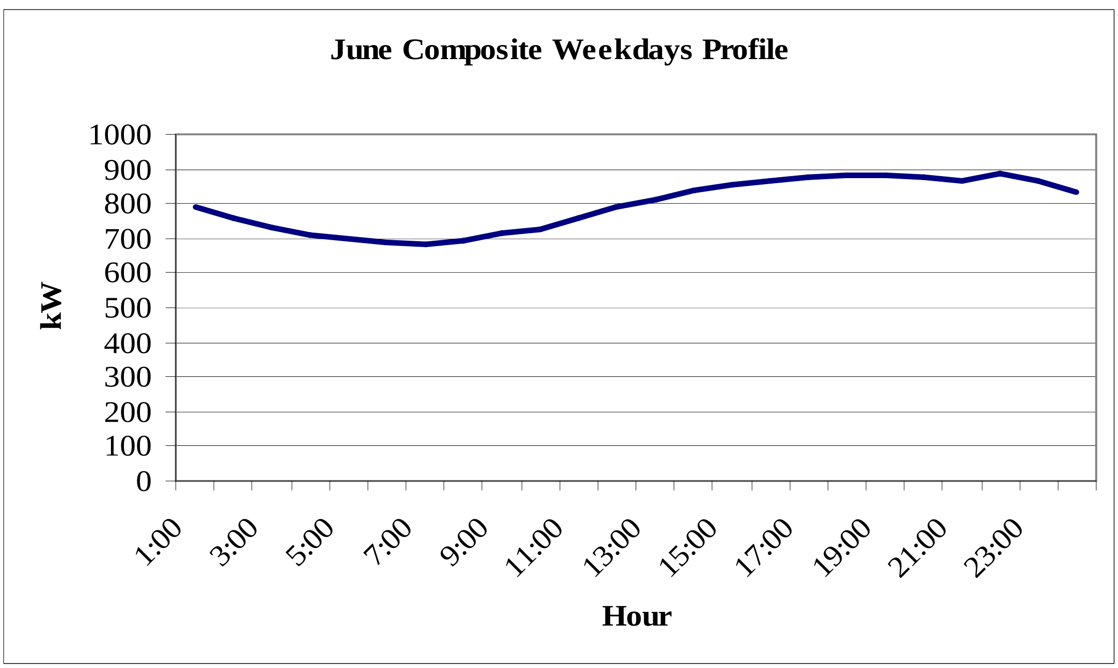

Figure 53. Commerce-8 June Weekday Average Energy Profile

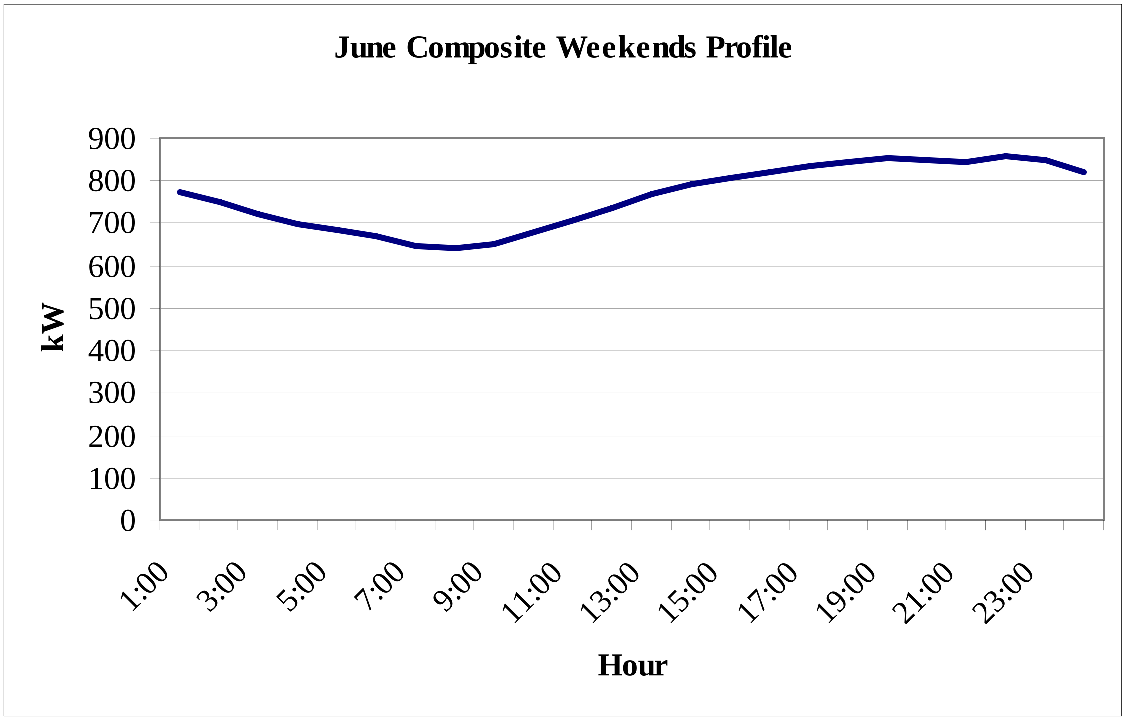

Figure 54. Commerce-8 June Weekend Average Energy Profile

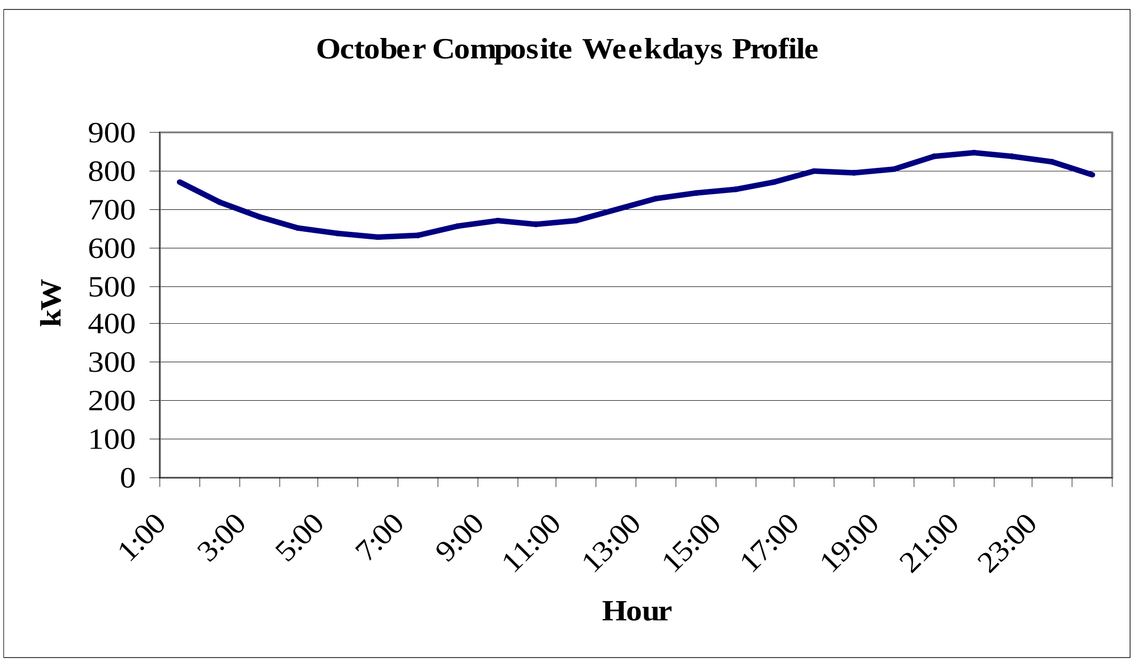

Figure 55. Commerce-8 October Weekday Average Energy Profile

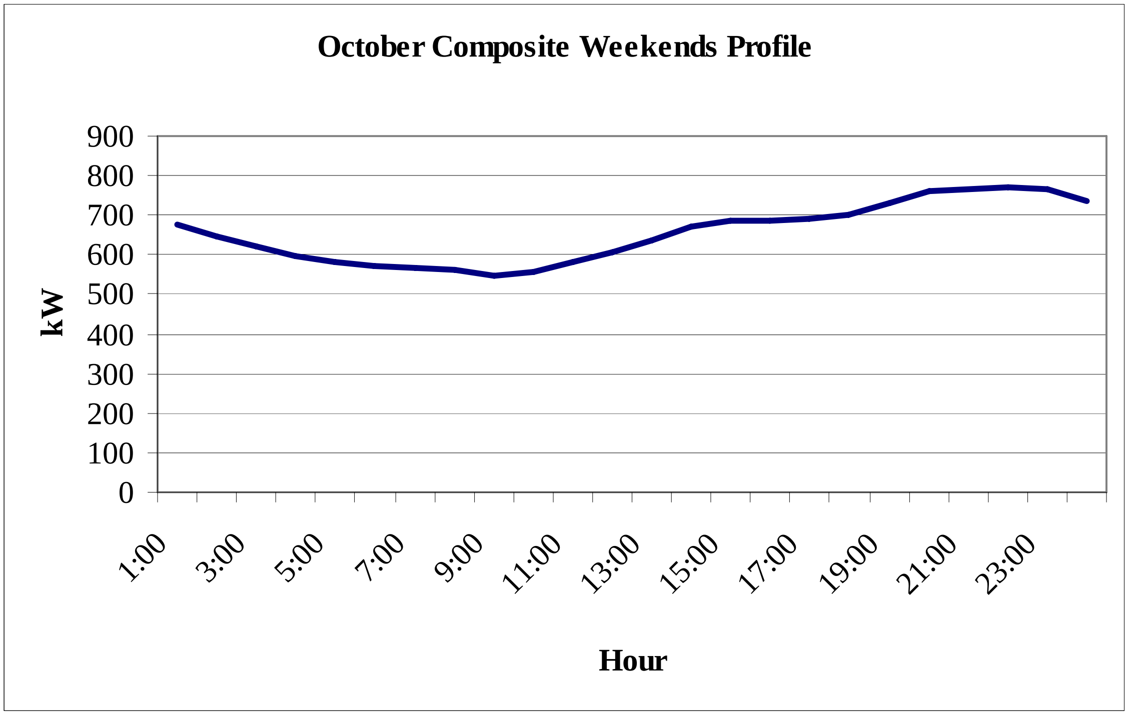

Figure 56. Commerce-8 October Weekend Average Energy Profile

F. Tarleton State University

Tarleton State University is located near the Dallas/Fort Worth Metroplex in Stephenville, TX. It has a 173 acre main campus, a 600-acre farm and a 1,200-acre ranch. It has approximately 76 buildings including academic buildings, dormitories, library, student recreational center, and laboratories. Approximately 9,000 students are enrolled, and it is located in the North Zone of ERCOT. TXU Electric Delivery provides the transmission and distribution services.

The Tarleton campus consumed 30,069,084 kWh from March 1, 2005 to February 28, 2006. August and September consumed the most energy in the year and the greatest monthly energy consumption was in September with 2,978,393 kWh. The lowest monthly energy consumption took place in December 2005 with 2,144,718 kWh. See Table 12.

Table 12. Tarleton Monthly Energy Consumption

Tarleton		
Total Monthly Energy Consumption (kWh)	**Mar-05**	2,273,407.20
	Apr-05	2,346,264.00
	May-05	2,257,544.16
	Jun-05	2,681,189.28
	Jul-05	2,812,561.92
	Aug-05	2,959,129.44
	Sep-05	2,978,393.76
	Oct-05	2,661,282.72
	Nov-05	2,454,046.56
	Dec-05	2,144,718.72
	Jan-06	2,228,987.52
	Feb-06	2,271,559.68
TOTAL		30,069,084.96

From the total energy consumed from March 1 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 57 for an average of energy consumption for these periods for different months. From the 69% of energy consumed from 6 am to 10 pm, 17% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1st to August 31st, 2005 this campus consumed 52% of its total load during on-peak hours and 48% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 43% of the total energy during peak periods and 57% during off-peak times from September 1, 2005 to February 28, 2006.

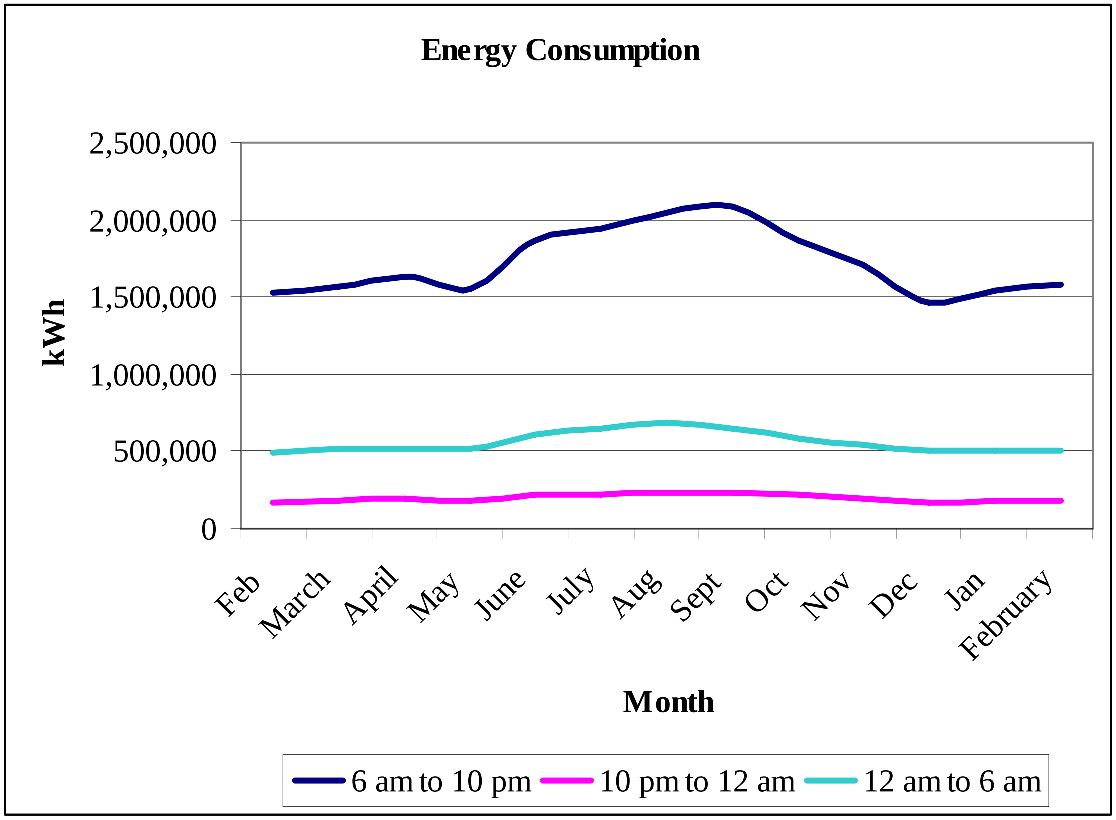

Figure 57. Tarleton Monthly Energy Consumption

Overall, from February to May the peak demand during weekdays varied from 3700 to 4200 kW; from June to July the peak demand varied from 4000 kW to a little over 4800 kW; from August to September the peak demand varied from 4400 to 5300 kW; in October the peak demand varied from 4000 to 5100 kW, and from November to December the peak demand varied from 2200 to 4800 kW. Most of the time, the peak demand occurred from 3 pm to 4 pm.

In general, the peak demand during weekdays occurred from noon to 5 pm and from 5 pm to 9 pm during the weekends. The lowest consumption of energy during weekdays occurred early morning, most of the time at 4 am. During the weekends, the lowest energy consumption took place early morning, most of the time from 8 am to 9 am. The lowest energy consumption was around 2900 to 3400 kW during January, February, March, November, and December. See Figures 58 through 63 for Tarleton weekdays and weekends average energy profiles.

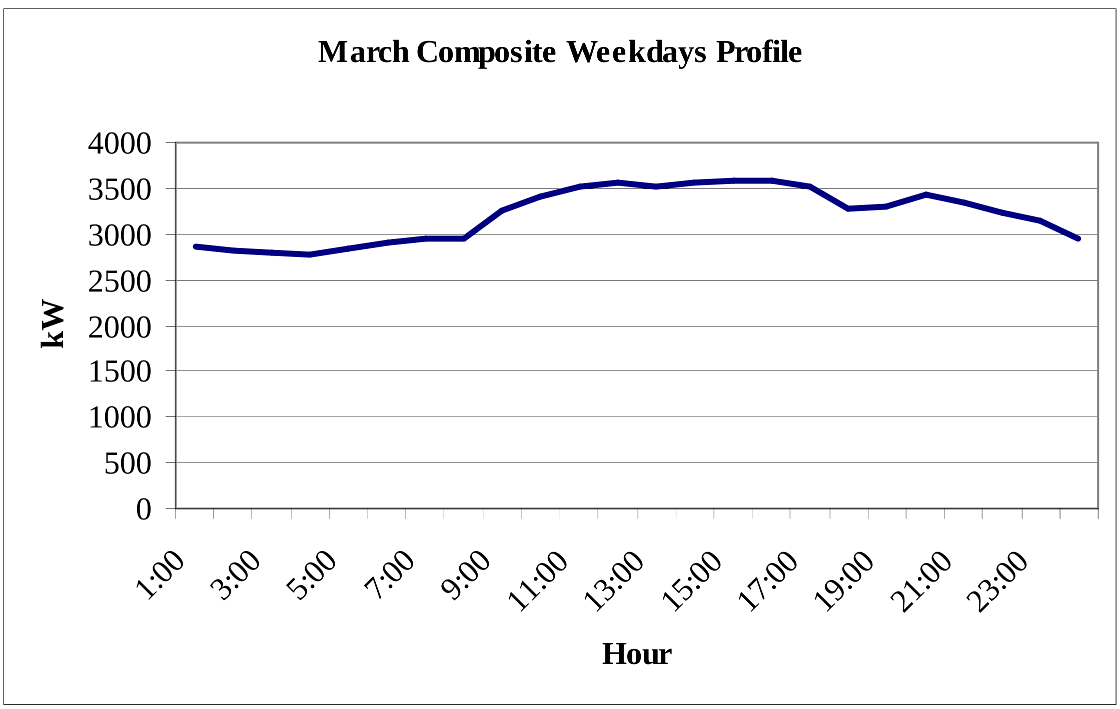

Figure 58. Tarleton March Weekday Average Energy Profile

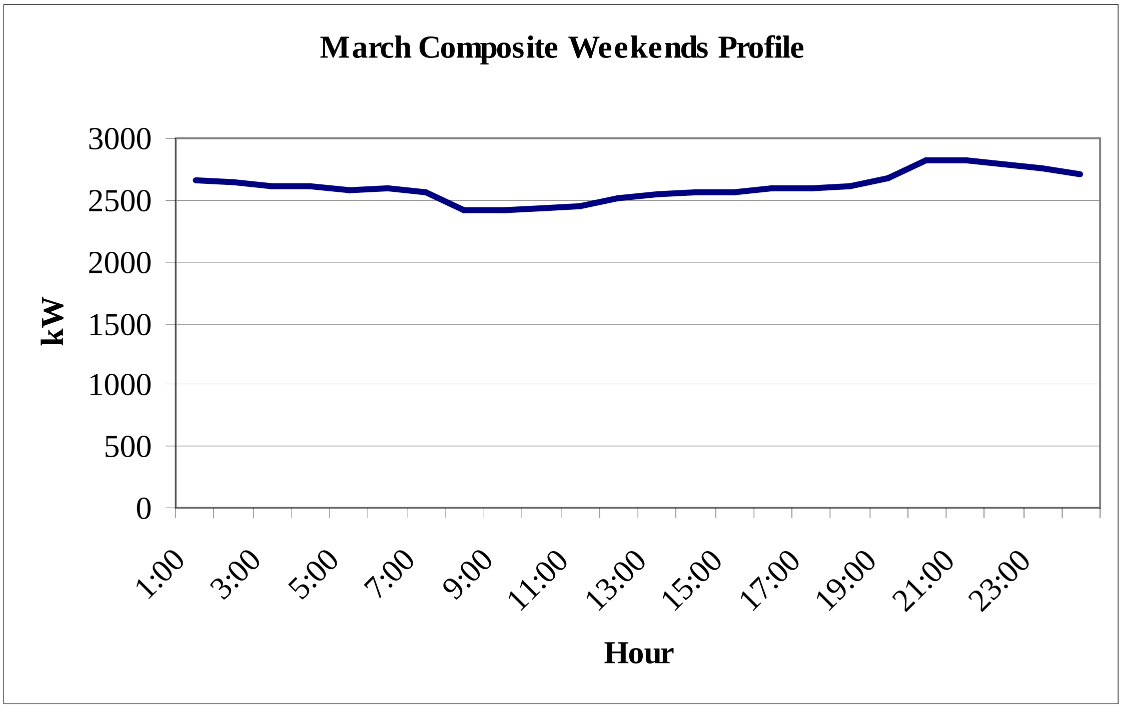

Figure 59. Tarleton March Weekend Average Energy Profile

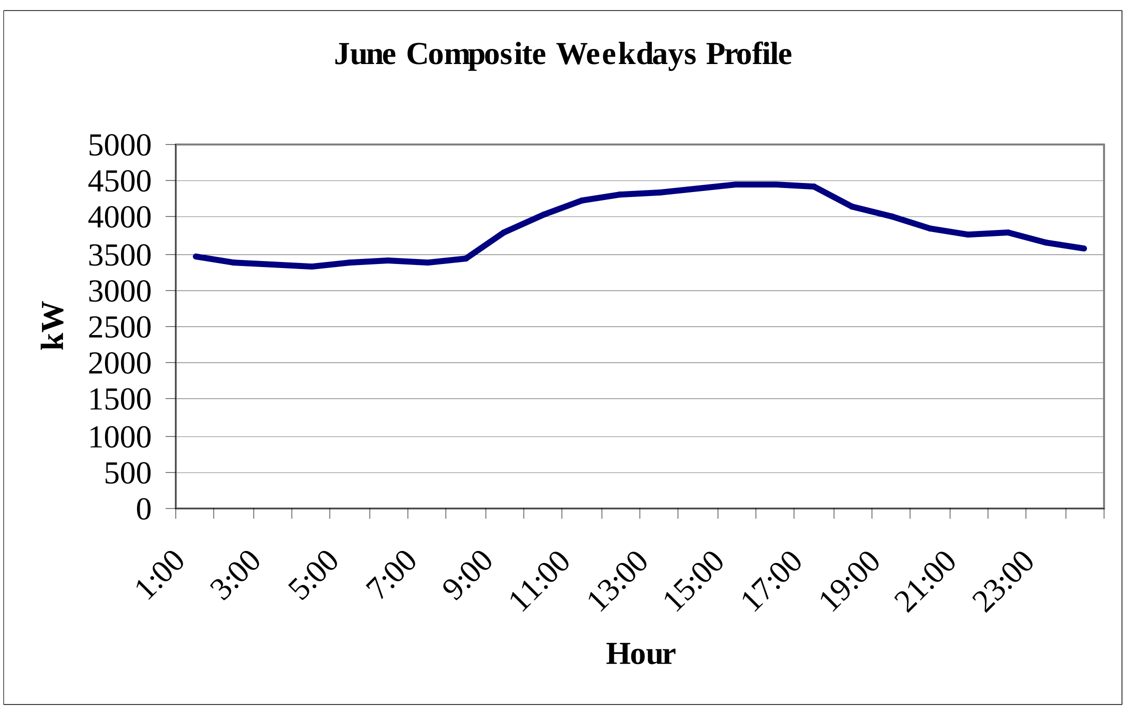

Figure 60. Tarleton June Weekday Average Energy Profile

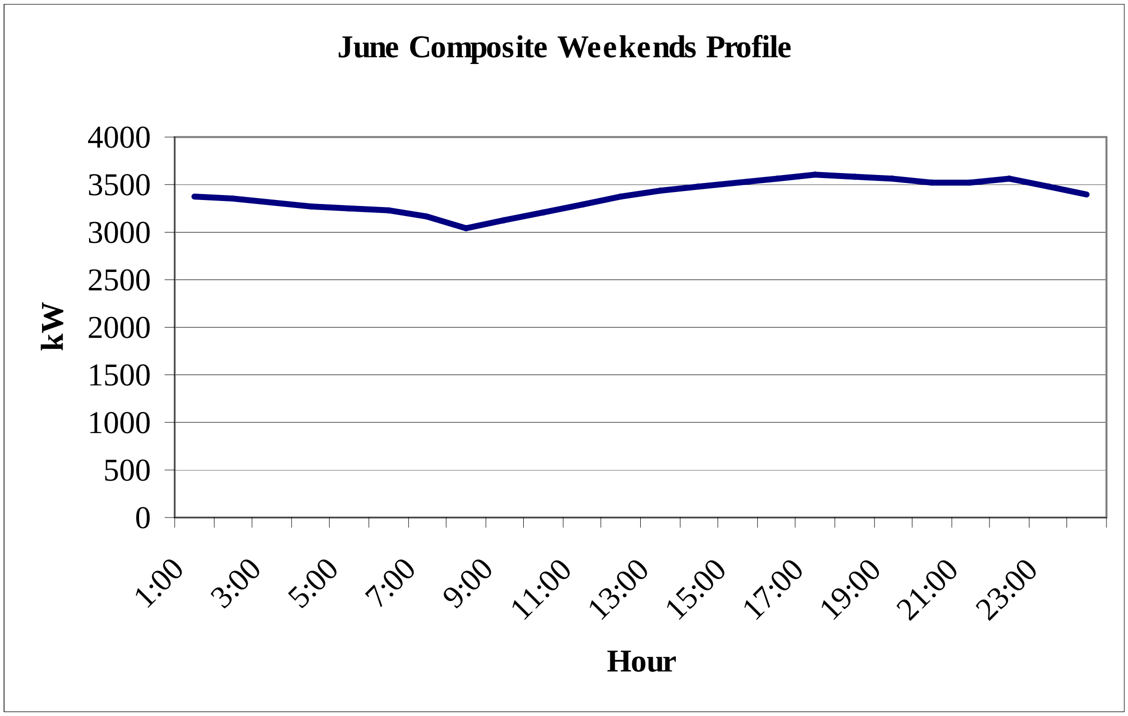

Figure 61. Tarleton June Weekend Average Energy Profile

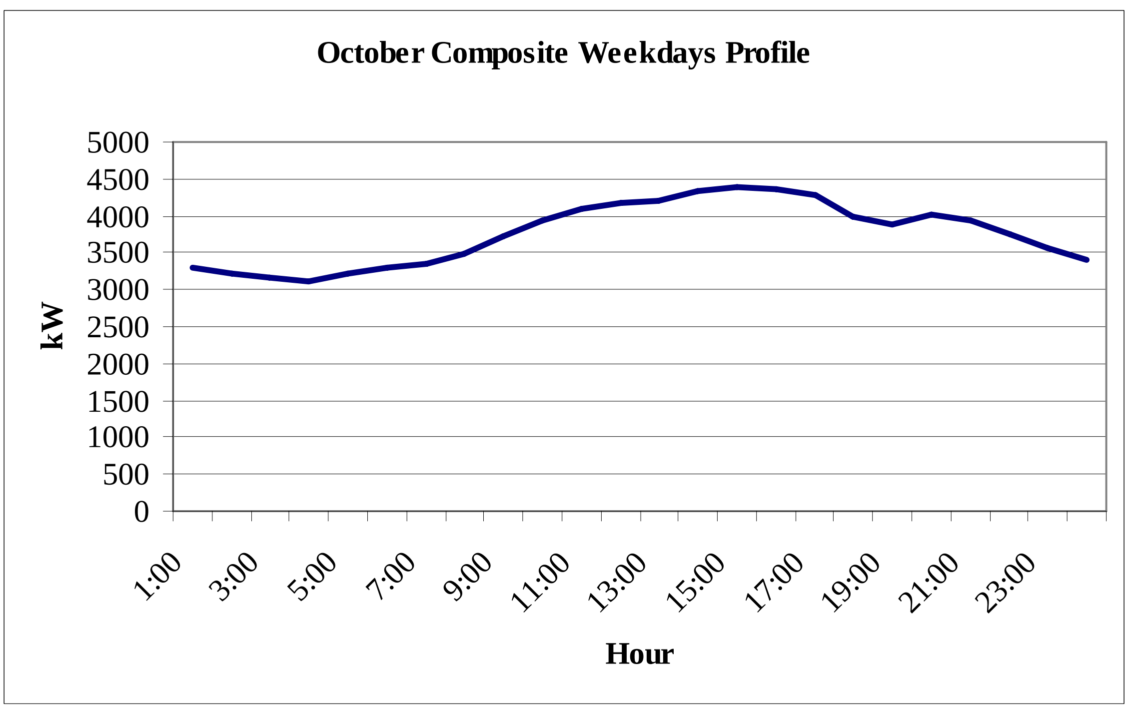

Figure 62. Tarleton October Weekday Average Energy Profile

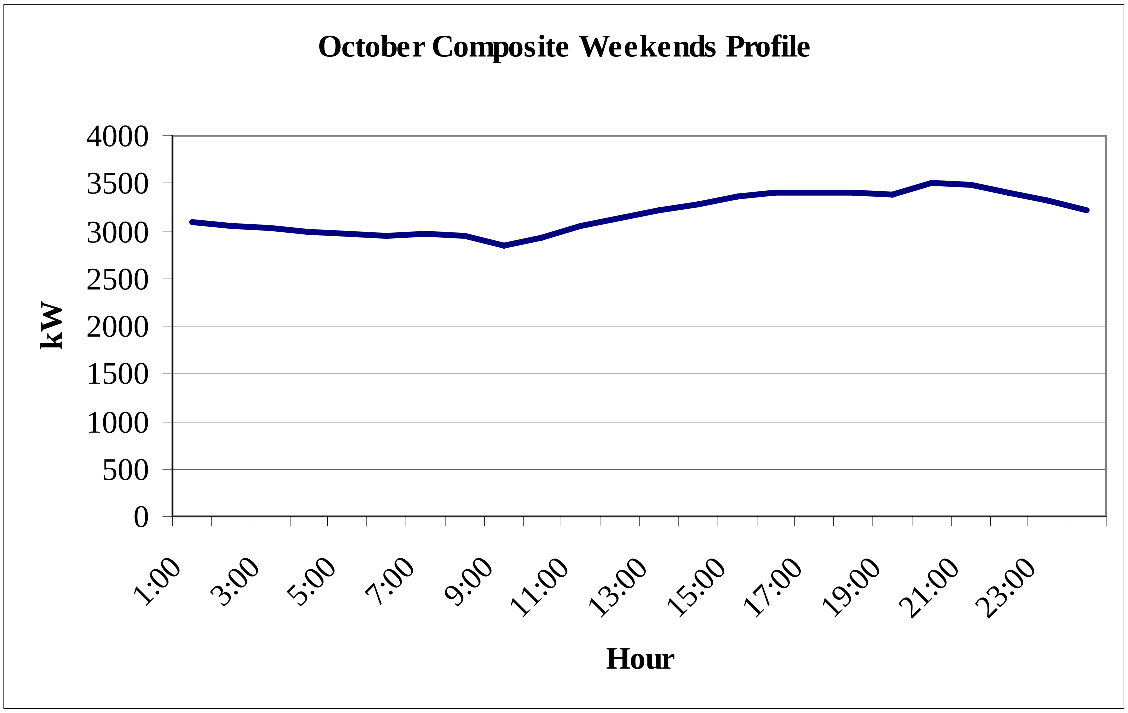

Figure 63. Tarleton October Weekend Average Energy Profile

G. Institute of Biosciences and Technology (IBT)

The Institute of Biosciences and Technology is located in the Albert B. Alkek Building in the medical center in Houston. It is an institute for cancer, animal and nutrition research. It is an 11-story building and it has approximately 100 students and 60 faculty members. It has different laboratories and equipment for research and several computers. The IBT facility is located in the Houston Zone of ERCOT, and Center Point Energy provides the transmission and distribution services.

The IBT facility consumed 7,537,708 kWh from March 2005 to February 2006. The greatest monthly energy consumption was in August with 661,406 kWh. The lowest monthly energy consumption took place in February 2006 with 563,934 kWh. See Table 13.

Table 13. IBT Monthly Consumption

IBT		
Total Monthly Energy Consumption (kWh)	**Mar-05**	640,655.00
	Apr-05	615,548.25
	May-05	640,261.25
	Jun-05	647,010.50
	Jul-05	656,992.00
	Aug-05	661,406.00
	Sep-05	624,043.50
	Oct-05	648,696.00
	Nov-05	605,385.50
	Dec-05	610,711.25
	Jan-06	623,065.25
	Feb-06	563,934.25
TOTAL		7,537,708.75

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 70% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 22% from midnight to 6 am. See Figure 64 for an average of energy consumption for these periods for different months. From the 70% of energy consumed from 6 am to 10 pm, 18% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 52% of its total load during on-peak hours and 48% during off-peak time. From September 1, 2005 to February 28, 2006, Sempra Energy agreed to change the on-peak time to 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 43% of the

total energy during peak periods and 57% during off-peak times from September 1, 2005 to February 28, 2006.

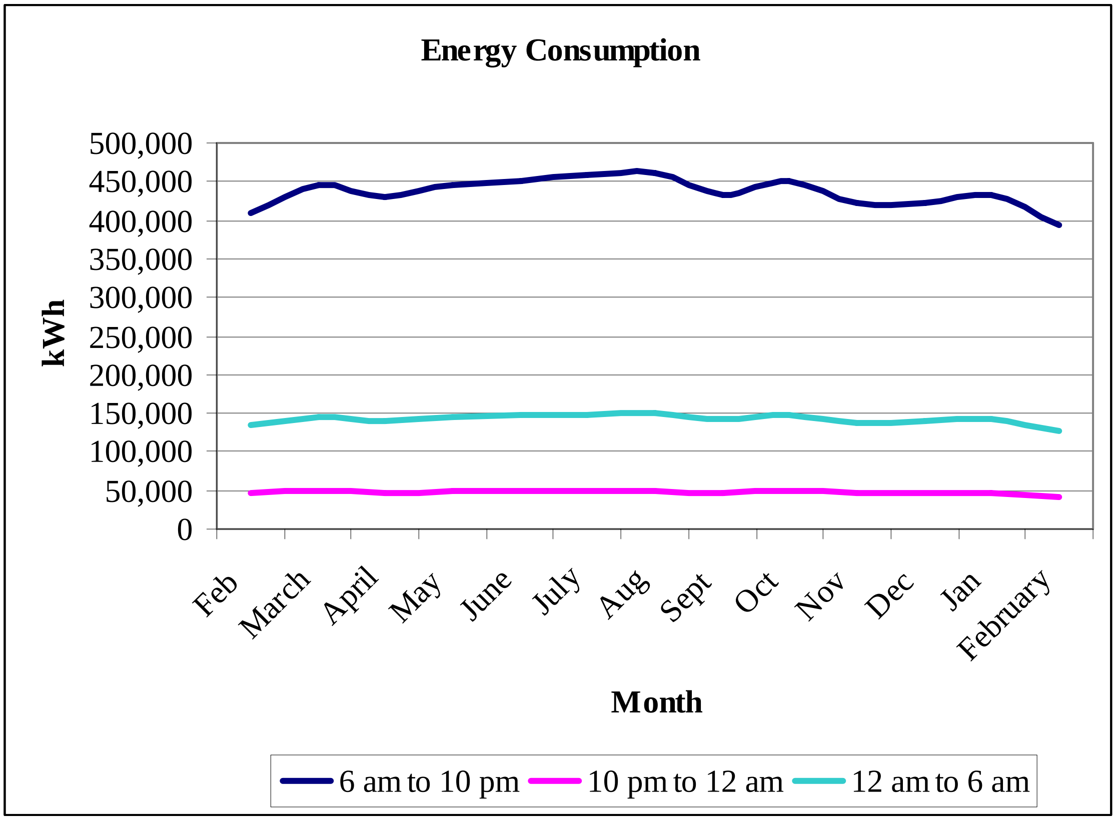

Figure 64. IBT Monthly Energy Consumption

The peak demand during weekdays varied from 900 kW to less than 1100 kW. Most of the time, the peak demand occurred around noon. In general, the peak demand during weekdays occurred from noon to 3 pm and from noon to 4 pm during weekends. The lowest consumption of energy during weekdays occurred early morning, most of the time around 5 am. During the weekends, the lowest energy consumption occurred early morning, most of the time from 11 pm to 5 am. The lowest energy consumption was around 700 kW during January, February, March, November, and December. See Figures 65 through 70 for IBT weekdays and weekends average energy profiles.

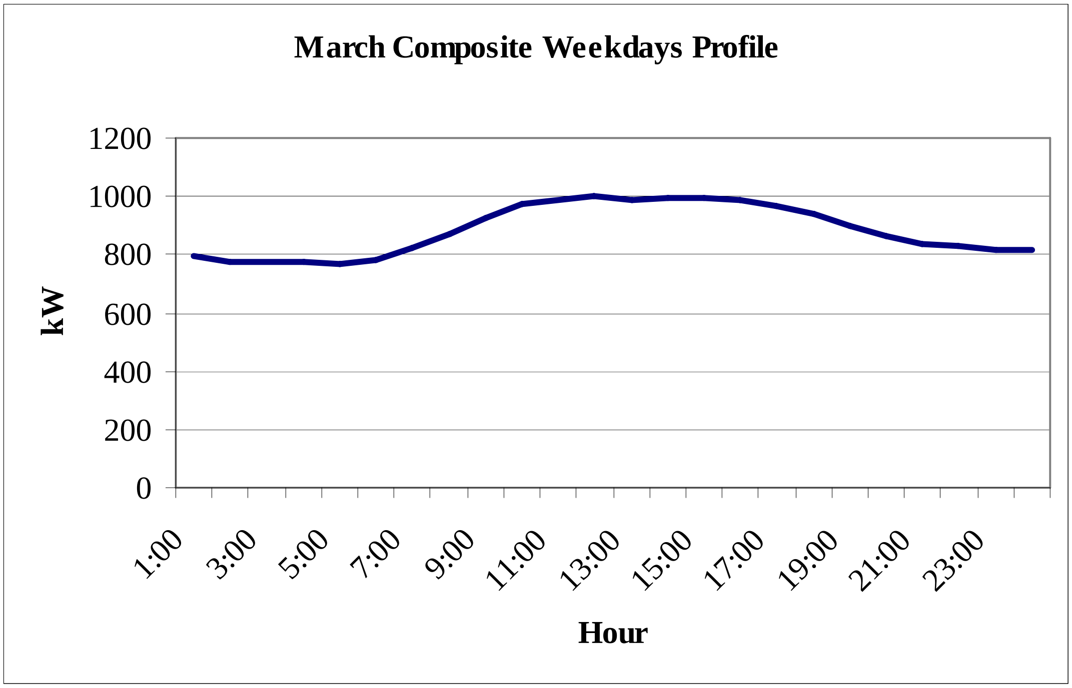

Figure 65. IBT March Weekday Average Energy Profile

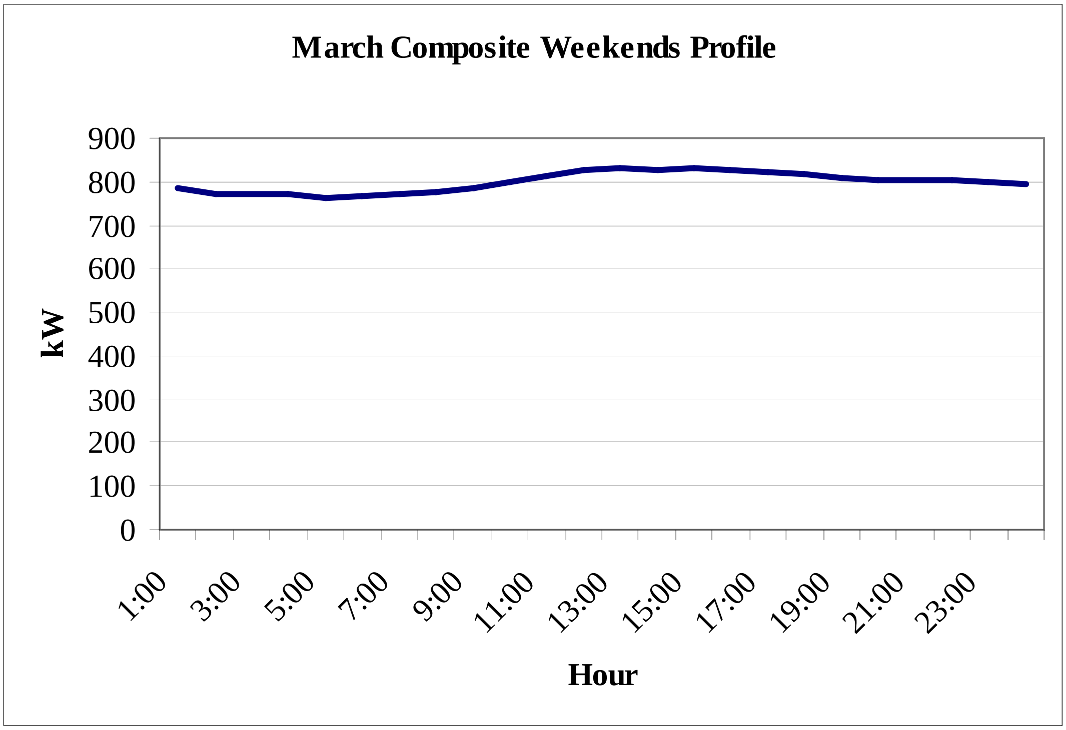

Figure 66. IBT March Weekend Average Energy Profile

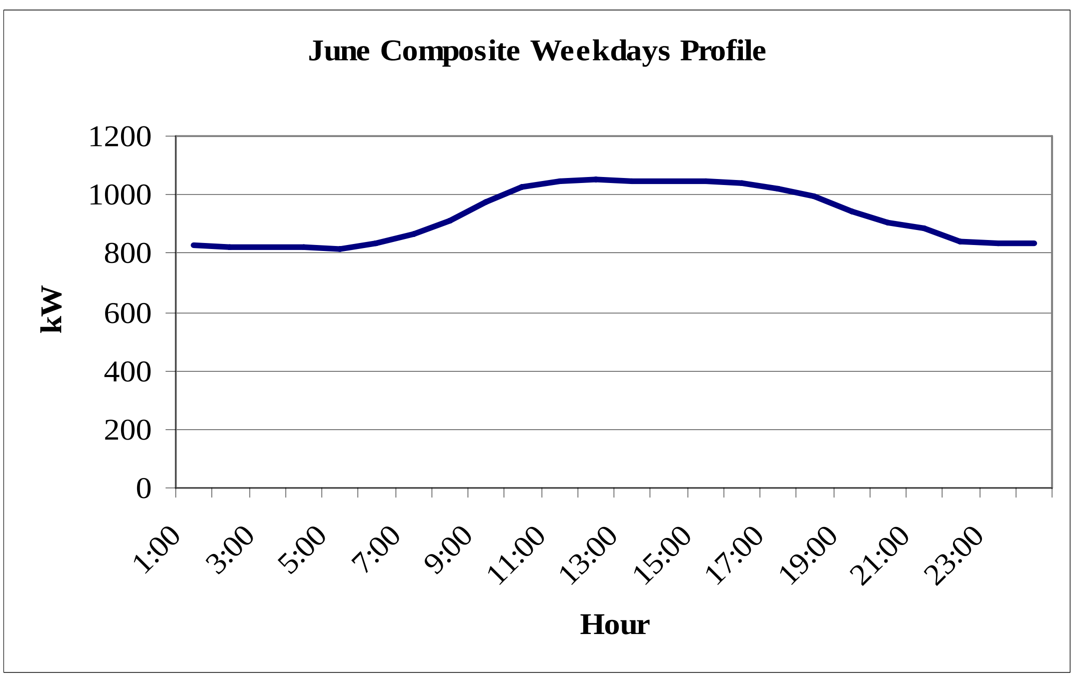

Figure 67. IBT June Weekday Average Energy Profile

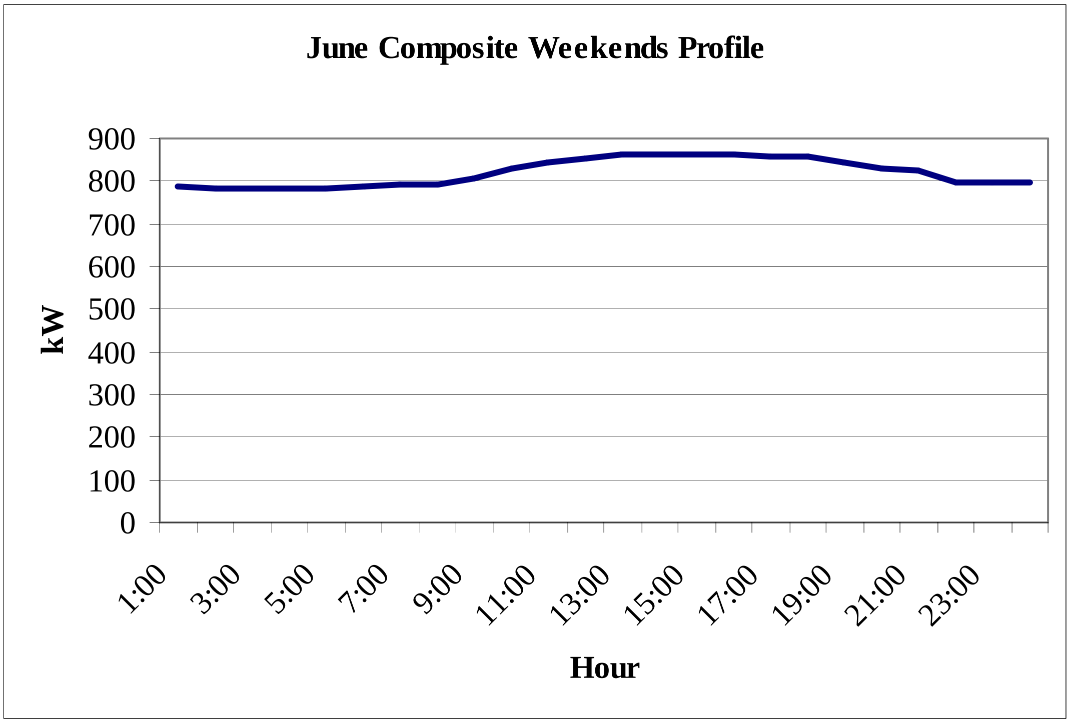

Figure 68. IBT June Weekend Average Energy Profile

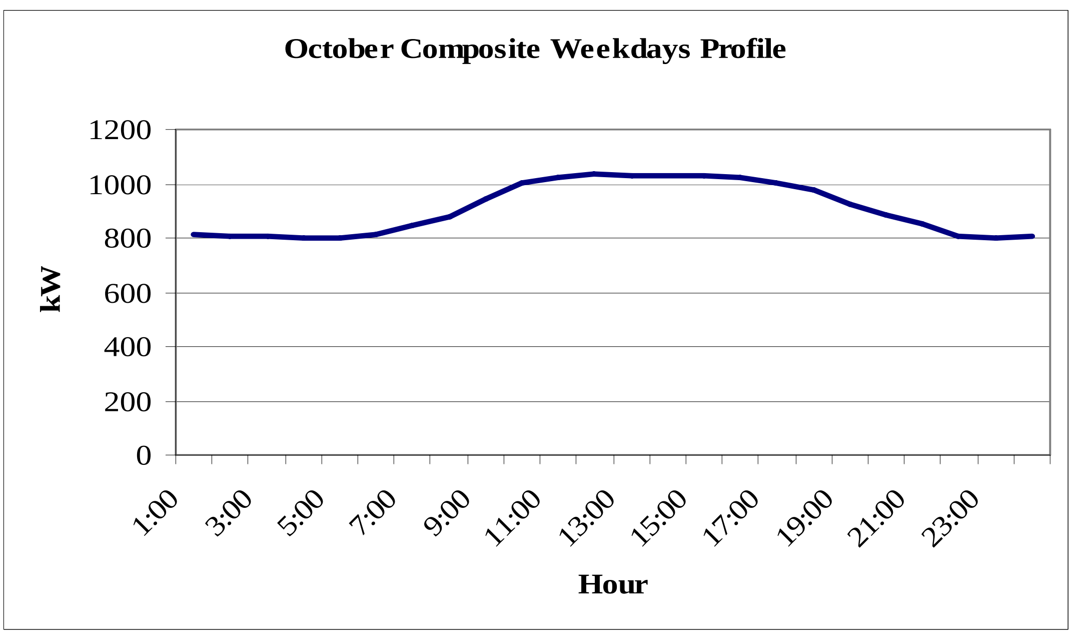

Figure 69. IBT October Weekday Average Energy Profile

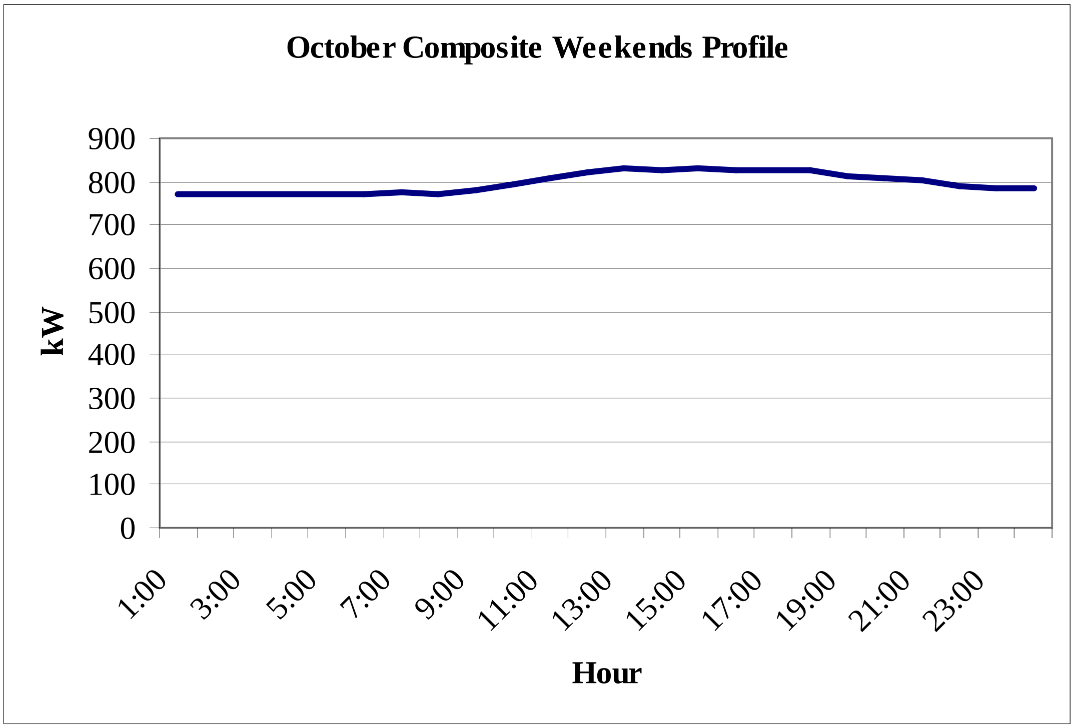

Figure 70. IBT October Weekend Average Energy Profile

H. Stephen F. Austin University

Stephen F. Austin University is located in Nacogdoches, Texas. It has approximately 11,000 students, 28 academic buildings, and 19 dormitories. The university also includes a 642 acre farm that is used for the production of beef, poultry and swine. It also has an 18.7 acre experimental forest in southwestern Nacogdoches and a 25.3 forestry field station at Lake Sam Rayburn. Stephen Austin State University is located in the North Zone of ERCOT, and TXU Electric Delivery provides the transmission and distribution services.

The SFA campus consumed 78,161,027 kWh from March 2005 to February 2006. August and September consumed the most energy during the year and the greatest monthly energy consumption was in September with 7,312,239 kWh. The lowest monthly energy consumption took place in December 2005 with 5,635,368 kWh. See Table 14.

Table 14. SFA Monthly Energy Consumption

SFA		
Total Monthly Energy Consumption (kWh)	**Mar-05**	6,167,986.56
	Apr-05	6,530,572.80
	May-05	6,571,149.12
	Jun-05	6,901,522.56
	Jul-05	6,956,040.96
	Aug-05	7,231,800.96
	Sep-05	7,312,239.36
	Oct-05	6,868,897.92
	Nov-05	6,339,159.36
	Dec-05	5,635,368.00
	Jan-06	5,860,992.96
	Feb-06	5,791,296.96
TOTAL		78,167,027.52

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 71 for an average of energy consumption for these periods for different months. From the 69% of energy consumed from 6 am to 10 pm, 18% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 51% of its total load during on-peak hours and 49% during off-peak time. In the fiscal year 2006 contract, the on-peak time period was changed, and from September 1, 2005 to February 28, 2006, the on-peak time was 6 am to 7 pm during weekdays. According to the new on-peak schedule, this facility consumed 42% of the total energy during peak periods and 58% during off-peak times from September 1, 2005 to February 28, 2006.

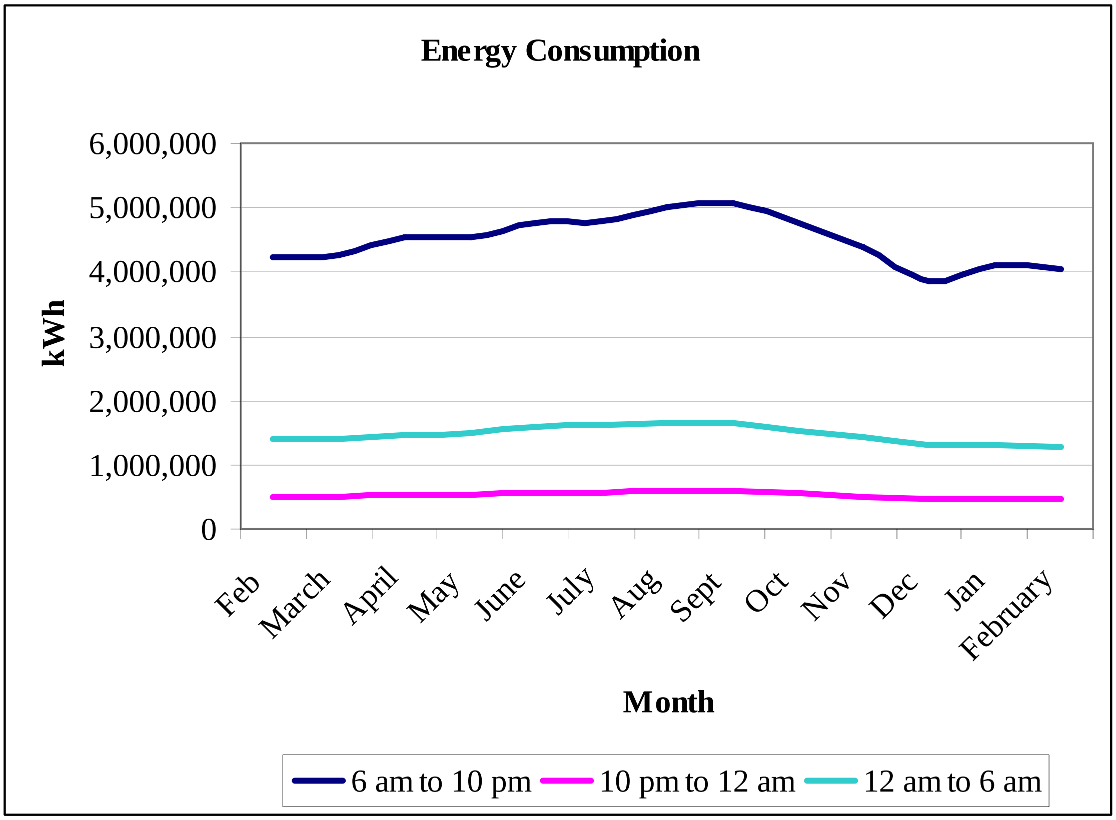

Figure 71. SFA Monthly Energy Consumption

In general, the peak demand during weekdays varied from 10,000 to 12,000 kW. Most of the time, the peak demand occurred from 3 pm to 4 pm. The peak demand during weekdays occurred from noon to 5 pm and from noon to 8 pm during the weekends. The lowest consumption of energy during weekdays occurred early morning, most of the time from 5 am to 6 am. During the weekends, the lowest energy consumption occurred early morning, most of the time around 8 am. The lowest energy consumption was around 6000 to 8000 kW during January, February, March, November, and December. See Figures 72 through 77 for SFA weekdays and weekends average energy profiles.

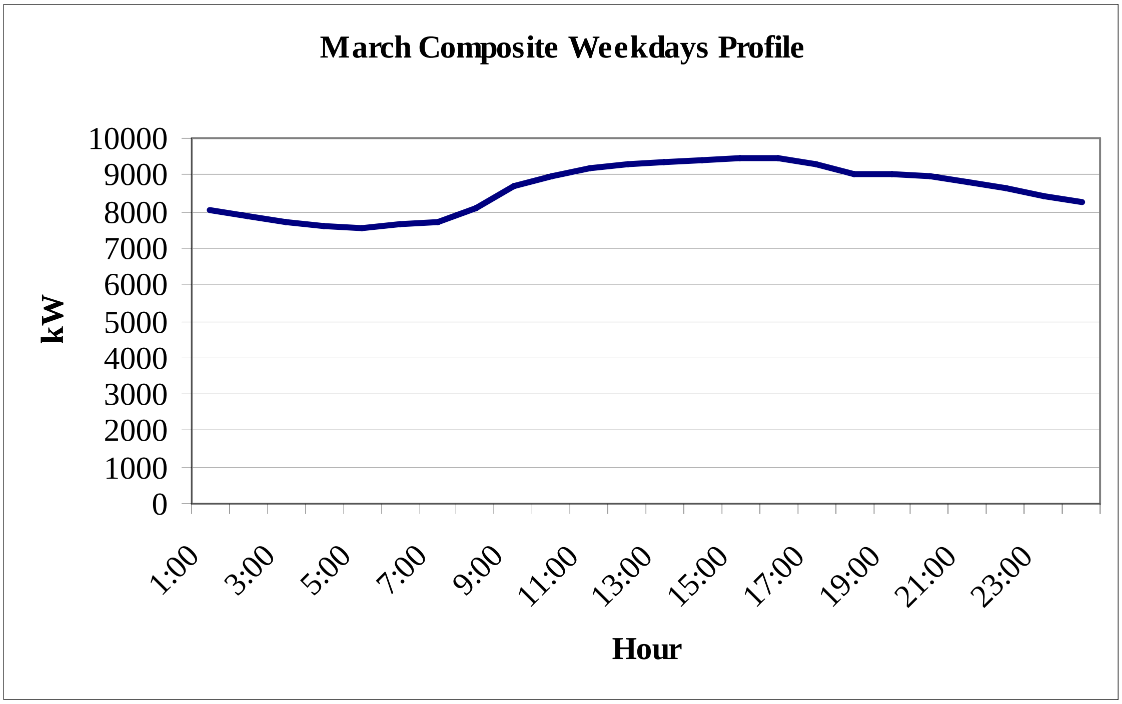

Figure 72. SFA March Weekday Average Energy Profile

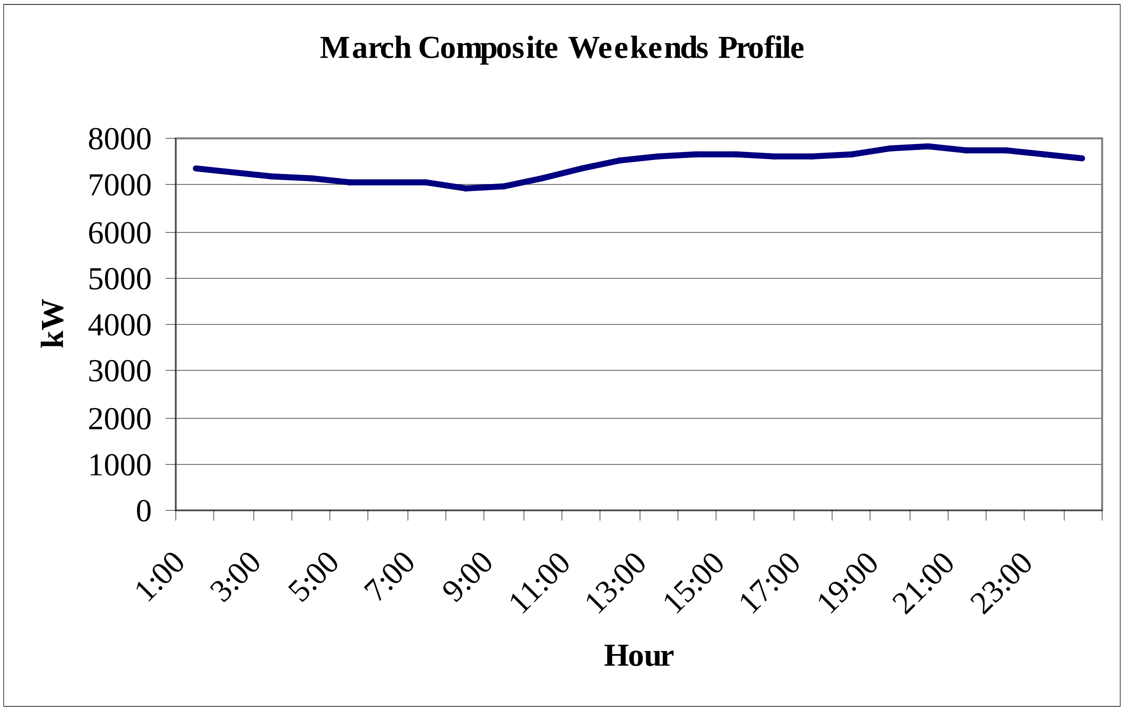

Figure 73. SFA March Weekend Average Energy Profile

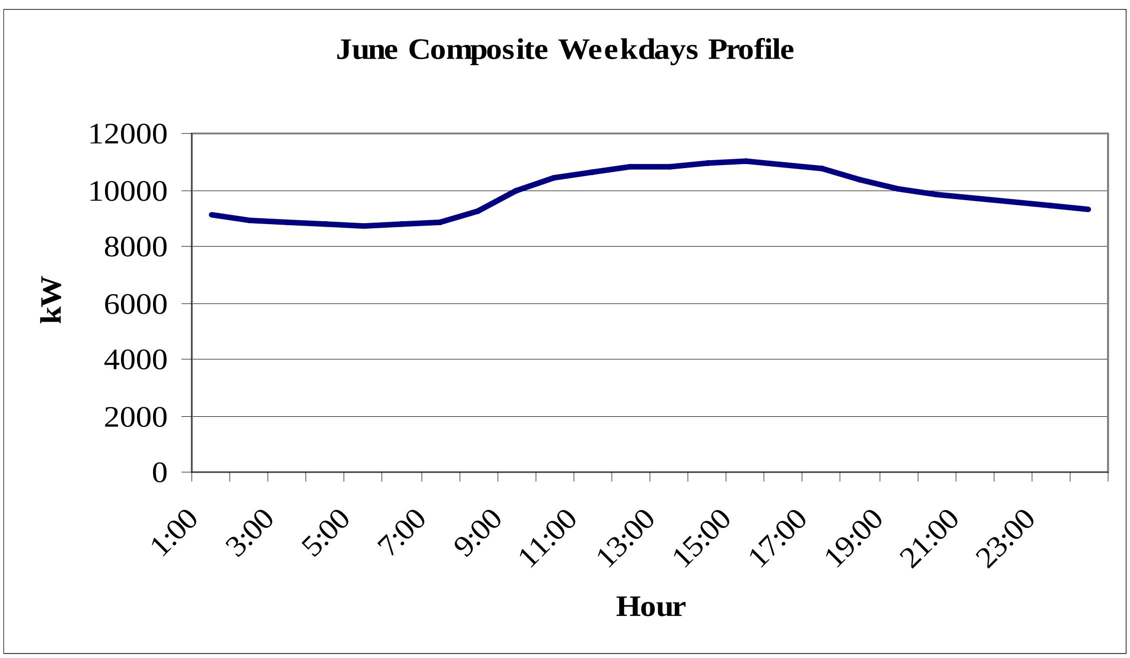

Figure 74. SFA June Weekday Average Energy Profile

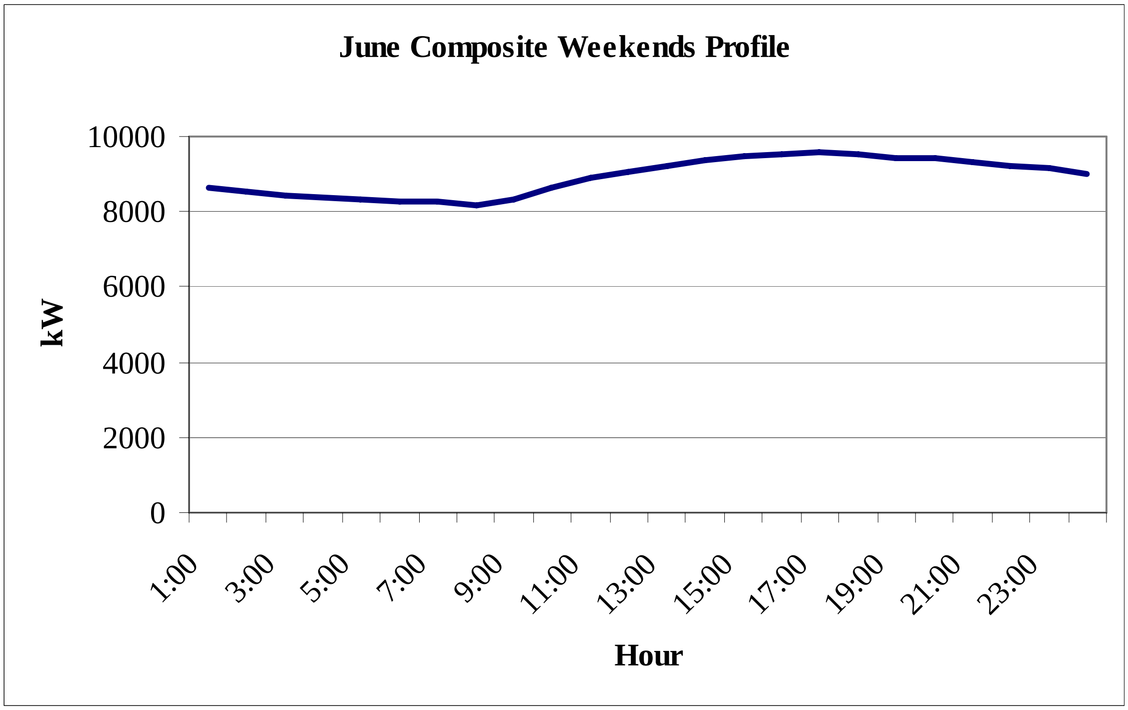

Figure 75. SFA June Weekend Average Energy Profile

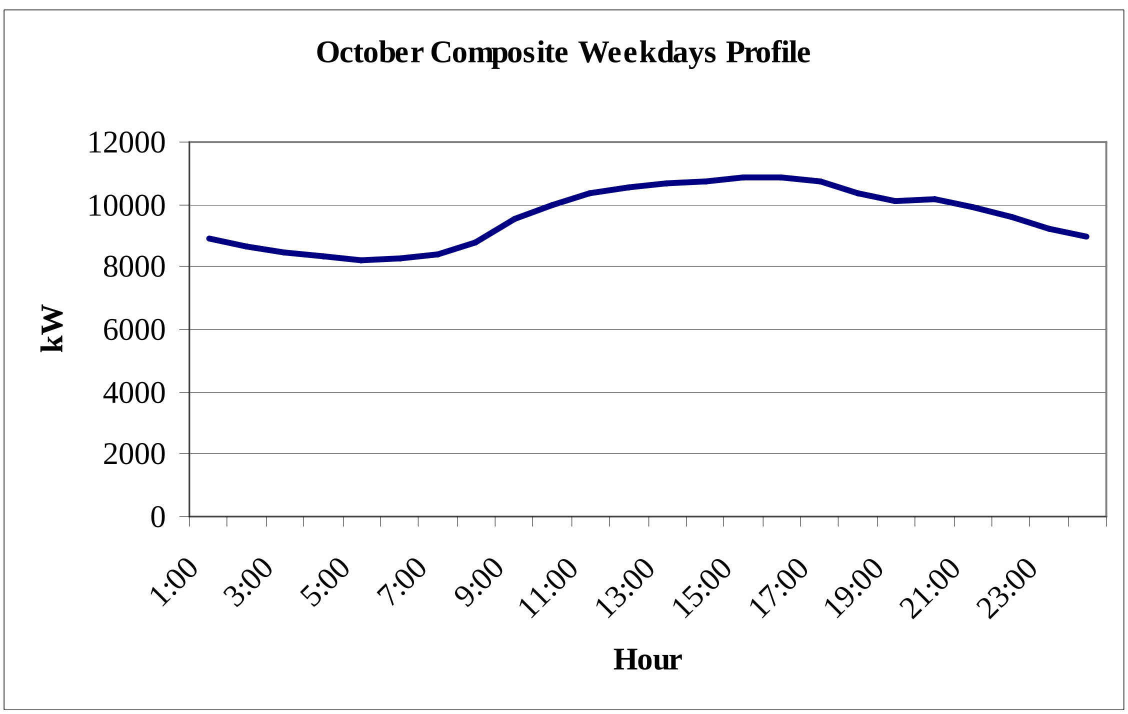

Figure 76. SFA October Weekday Average Energy Profile

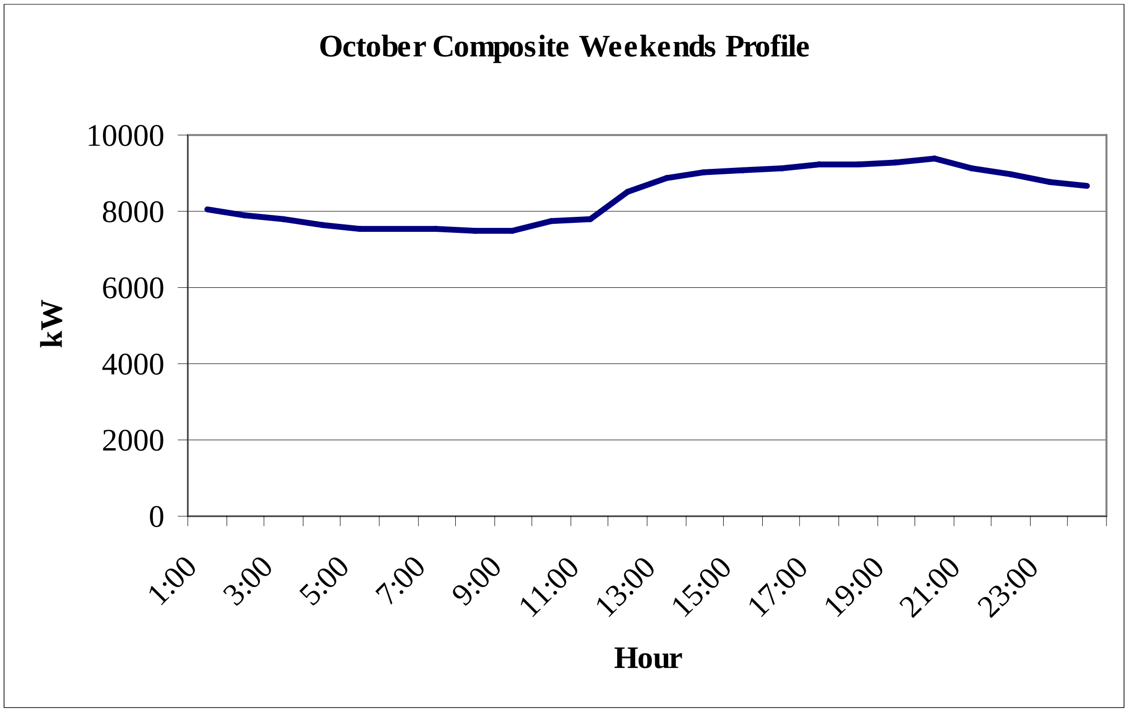

Figure 77. SFA October Weekend Average Energy Profile

I. Aggregation of All Loads

The aggregated loads of the eight facilities mentioned above, resulting in 9 IDR accounts, consumed around 242,745,688 kWh from March 2005 to February 2006. The greatest monthly energy consumption was in August 2005 with 23,909,893 kWh followed by September with 23,458,946 kWh. The lowest monthly energy consumption took place in February 2006 with 16,309,736 kWh. See Table 15.

Table 15. Monthly Consumption of the 9 IDRs Aggregated Load

All Facilities		
Total Monthly Energy Consumption (kWh)	**Mar-05**	18,511,397.11
	Apr-05	19,500,220.56
	May-05	20,027,315.36
	Jun-05	21,885,638.77
	Jul-05	22,753,692.15
	Aug-05	23,909,893.20
	Sep-05	23,458,946.27
	Oct-05	21,878,826.71
	Nov-05	19,468,394.13
	Dec-05	17,155,618.01
	Jan-06	17,886,009.87
	Feb-06	16,309,736.57
TOTAL		242,745,688.71

From the total energy consumed from March 1, 2005 to February 28, 2006, approximately 69% was consumed from the hours of 6 am to 10 pm, 8% from 10 pm to midnight, and 23% from midnight to 6 am. See Figure 78 for an average of energy consumption for these periods for different months. From the 69% of energy consumed from 6 am to 10 pm, 17% of this energy was consumed from 6 am to 10 pm during weekends (off-peak time). On-peak time was from 6 am to 10 pm during weekdays. From March 1 to August 31, 2005 this campus consumed 52% of its total load during on-peak hours and 48% during off-peak time. In the fiscal year 2006 purchase the on-peak time was changed to 6 am to 7 pm during weekdays, through a negotiation with Sempra Energy Solutions. According to the new on-peak schedule, these facilities consumed 43% of the total energy during peak periods and 57% during off-peak times from September 1, 2005 to February 28, 2006.

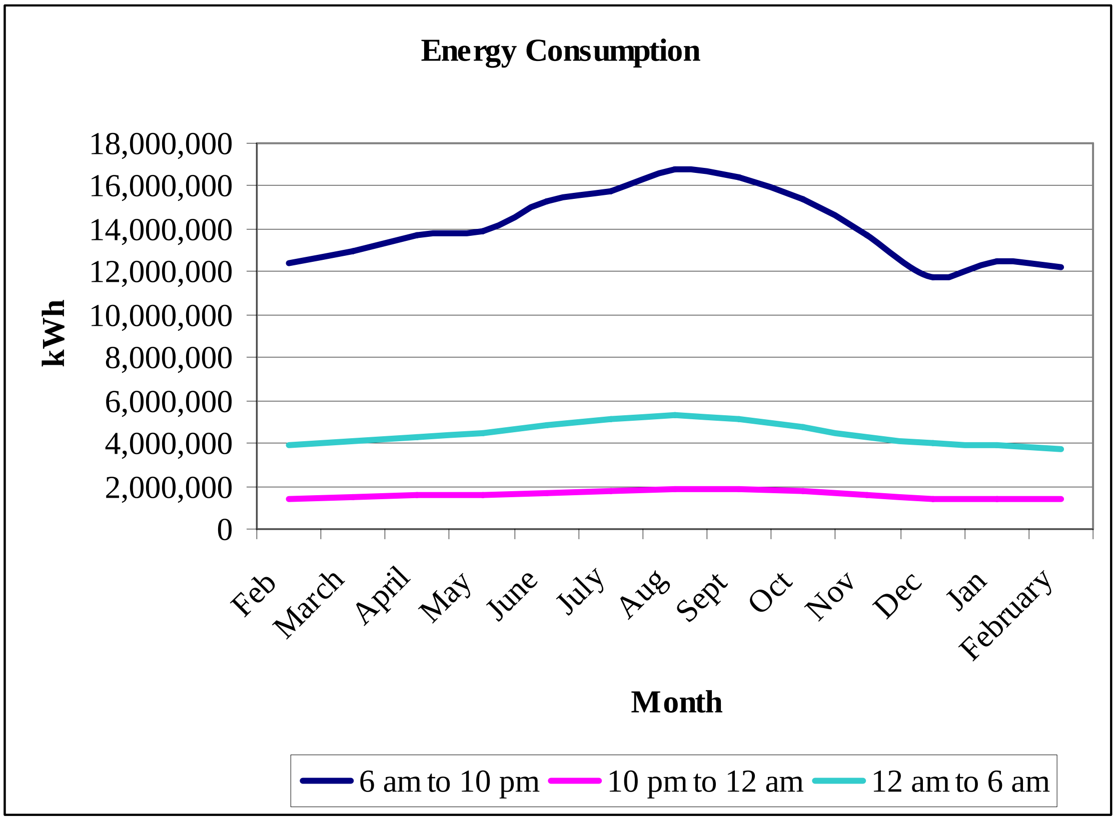

Figure 78. Monthly Energy Consumption of Aggregated Load of all 9 IDR Accounts

In the months of February and March the peak demand during weekdays varied from 22000 to 33000 kW; in April and May the peak demand varied from 29000 kW to a little over 33000 kW; from June to September the peak demand varied from 31000 kW to 41000 kW; during October and November the peak demand varied from 27000 kW to 38000 kW; in December the peak demand varied from 18000 to 31000 kW. Most of the time, the peak demand during weekdays occurred from 3 pm to 4 pm, and from 2 pm to 10 pm during the weekends.

In general, the lowest consumption of energy during weekdays occurred early morning, most of the time around 4 am. During the weekends, the lowest energy consumption occurred early morning, most of the time from 4 am to 9 am. The lowest energy consumption during weekdays varied from 17000 to 24000 kW during January, February, March, and December. See Figures 79 through 84 for the weekdays and weekends average energy profiles for the aggregated load of the 9 IDR accounts.

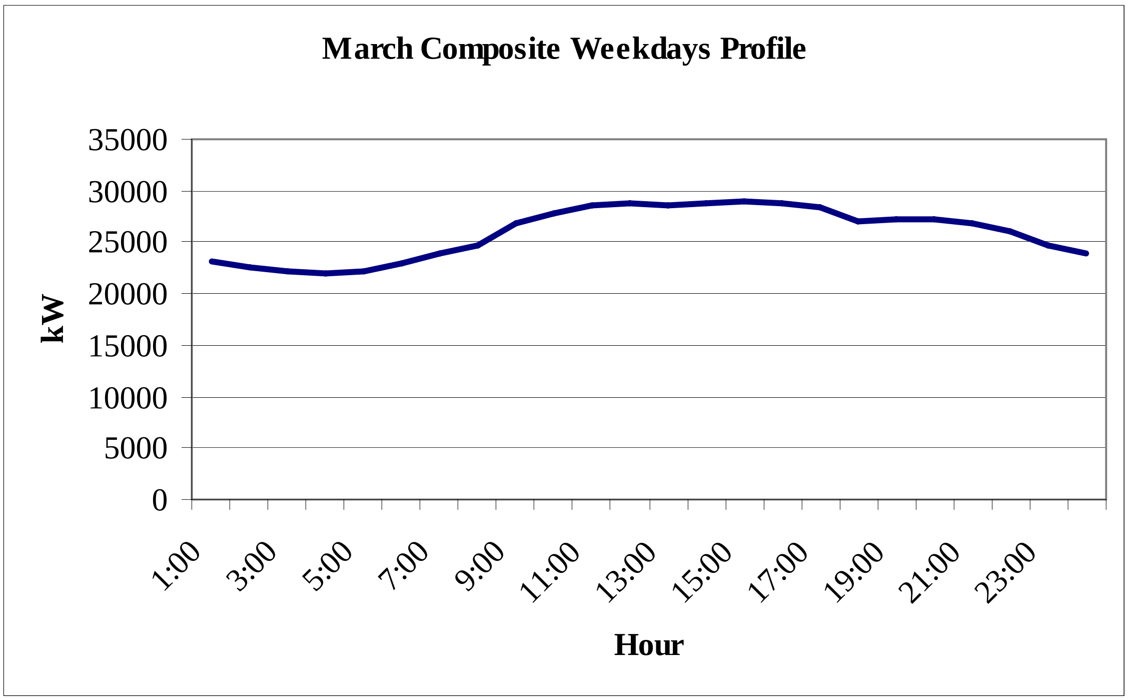

Figure 79. Aggregated Load, of all 9 IDR Accounts, March Weekday Average Energy Profile

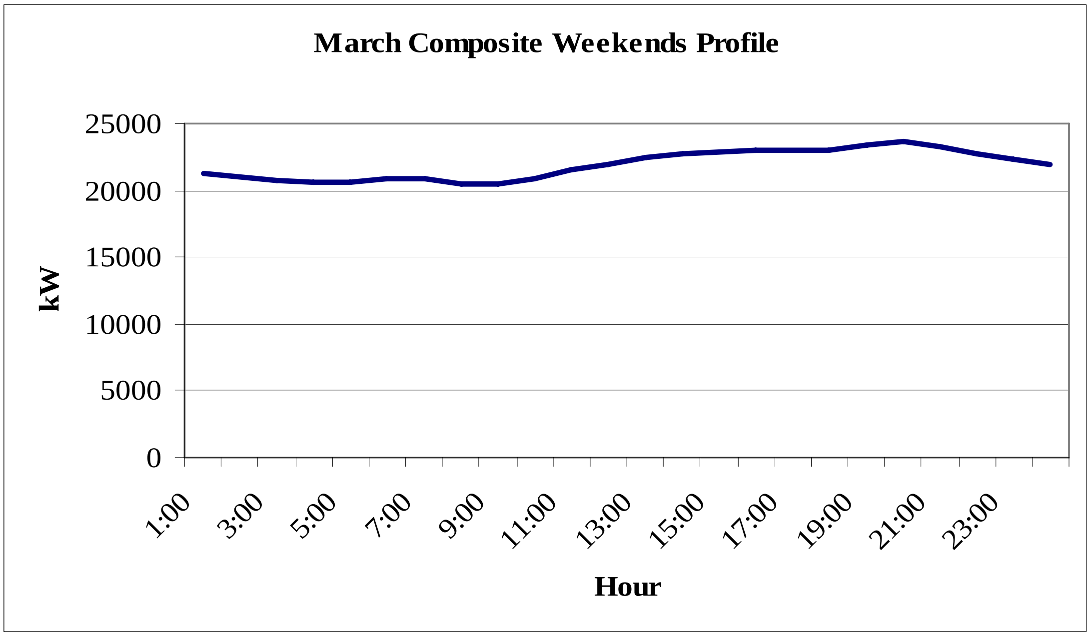

Figure 80. Aggregated Load, of all 9 IDR Accounts, March Weekend Average Energy Profile

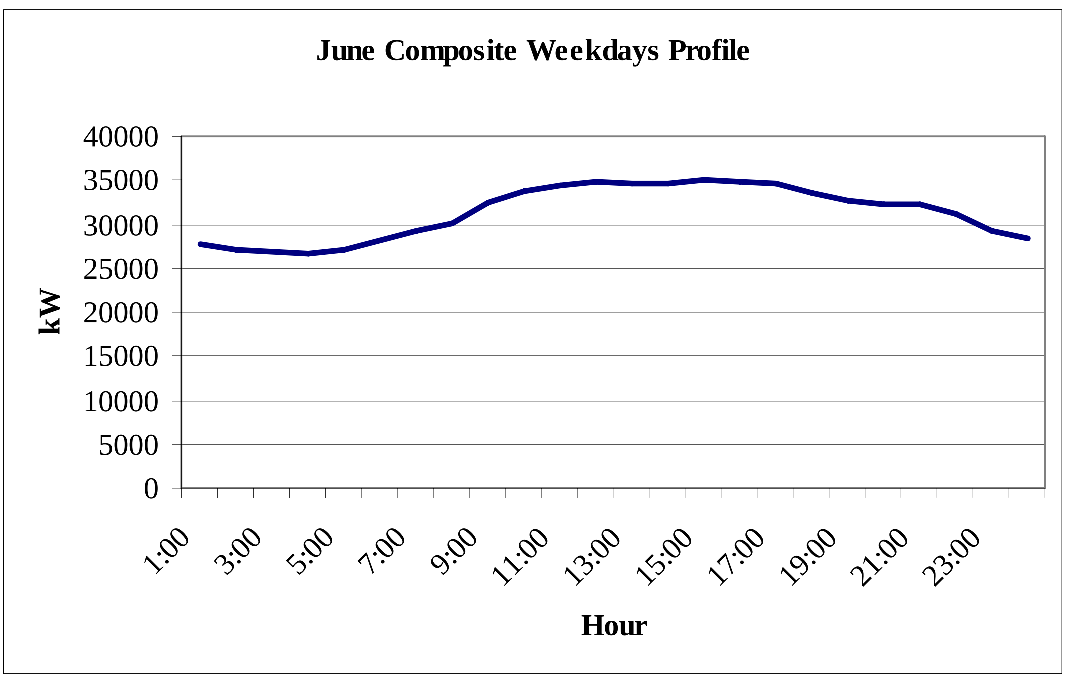

Figure 81. Aggregated Load, of all 9 IDR Accounts, June Weekday Average Energy Profile

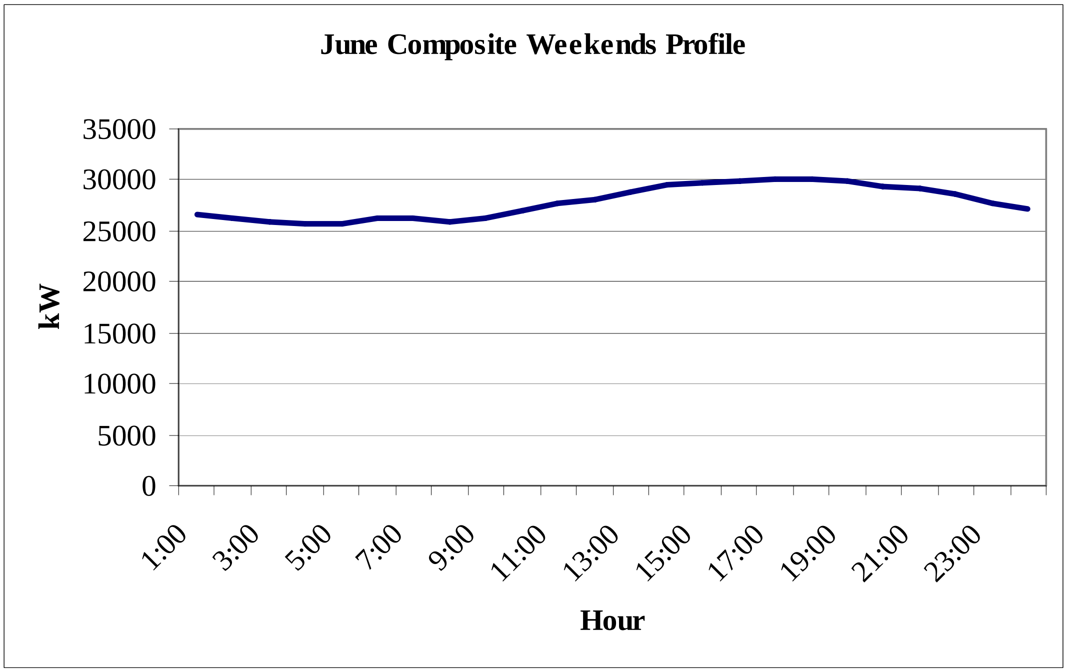

Figure 82. Aggregated Load, of all 9 IDR Accounts, June Weekend Average Energy Profile

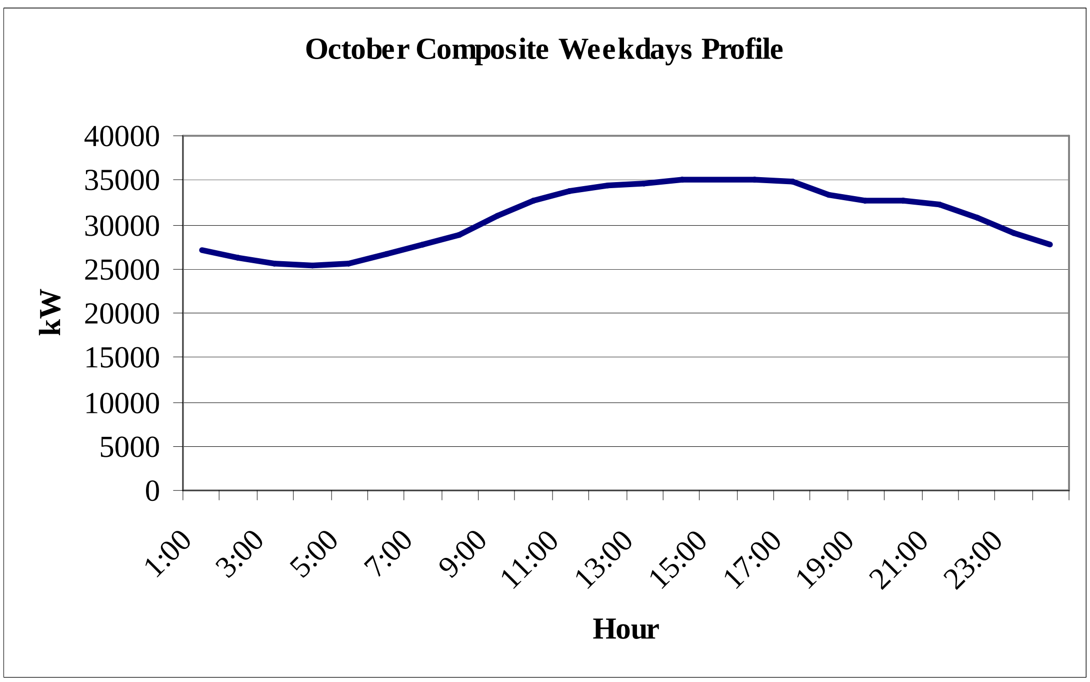

Figure 83. Aggregated Load, of all 9 IDR Accounts, October Weekday Average Energy Profile

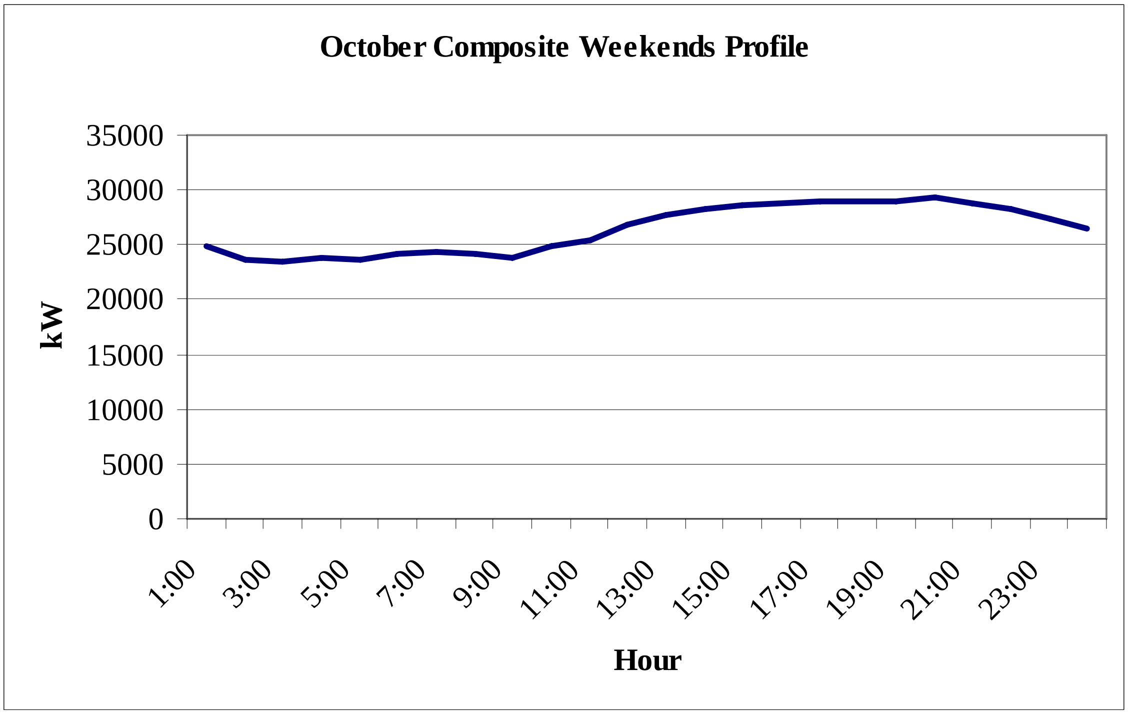

Figure 84. Aggregated Load, of all 9 IDR Accounts, October Weekend Average Energy Profile

J. Aggregation of Loads Without Corpus Christi

The load of 8 IDR accounts excluding Corpus Christi consumed around 210,219,513 kWh from March 2005 to February 2006. The greatest monthly energy consumption was in August with 20,562,933 kWh followed by September with 20,110,185 kWh. The lowest monthly energy consumption took place in February 2006 with 14,019,681.53 kWh. See Table 16.

Table 16. Monthly Consumption of Aggregated Load Excluding Corpus Christi

All Facilities Excluding Corpus		
Total Monthly Energy Consumption (kWh)	**Mar-05**	16,198,714.63
	Apr-05	17,036,340.24
	May-05	17,481,434.96
	Jun-05	19,031,828.05
	Jul-05	19,732,524.63
	Aug-05	20,562,933.12
	Sep-05	20,110,185.95
	Oct-05	18,812,262.23
	Nov-05	16,806,867.09
	Dec-05	14,918,334.17
	Jan-06	15,508,403.79
	Feb-06	14,019,681.53
TOTAL		210,219,510.39

In the months of February and March the peak demand during weekdays varied from 19000 to 29000 kW; in April and May the peak demand varied from 24000 kW to a little over 31000 kW; from June to September the peak demand varied from 29000 kW to 36000 kW; in October and November the peak demand varied from 24000 kW to 35000 kW, and in December the peak demand varied from 16000 to 26000 kW.

Most of the time, the peak demand occurred from 3 pm to 4 pm on weekdays and from 2 pm to 8 pm during the weekends. In general, the lowest consumption of energy during weekdays occurred early morning, most of the time around 4 am. During the weekends, the lowest energy consumption took place early morning, most of the time from 4 to 9 am. The lowest energy consumption during weekdays varied from 17000 to 21000 kW during January, February, March, and December. See Figures 85 through 90 for the weekdays and weekends average energy profiles for the aggregated load of 9 IDR accounts, excluding Corpus Christi.

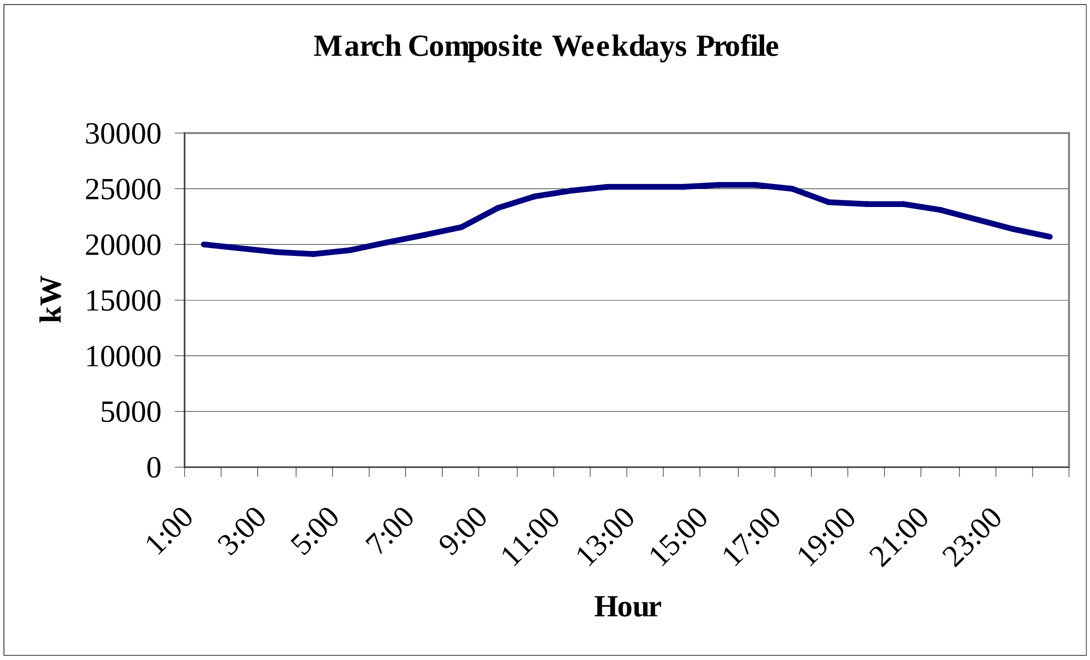

Figure 85. Aggregated Load, Excluding Corpus, March Weekday Average Energy Profile

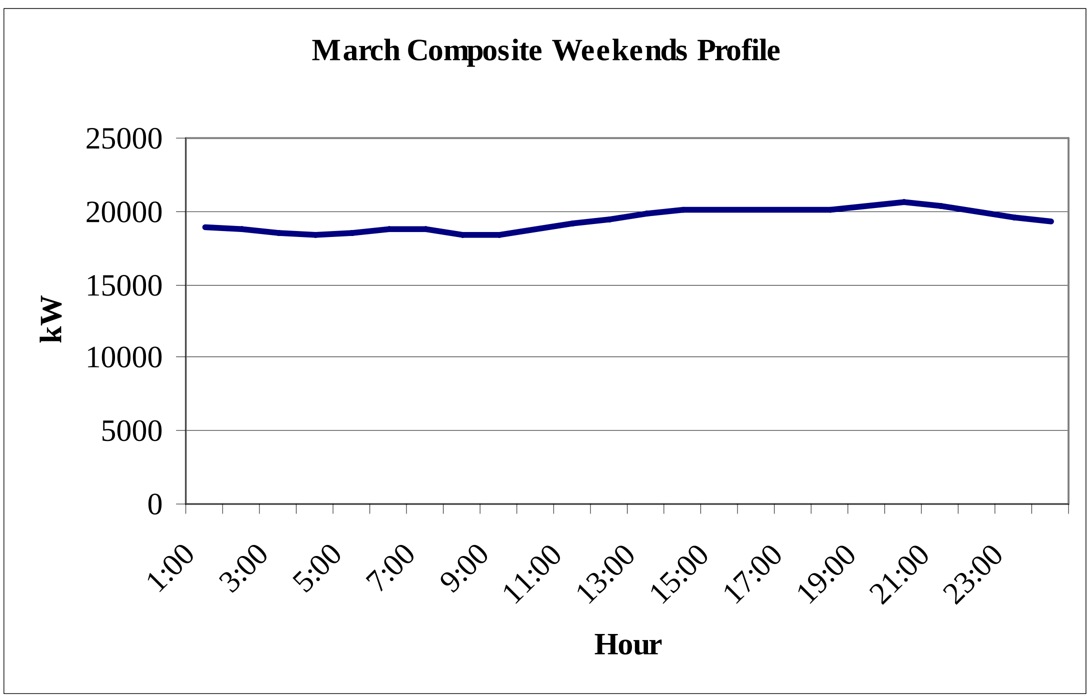

Figure 86. Aggregated Load, Excluding Corpus, March Weekend Average Energy Profile

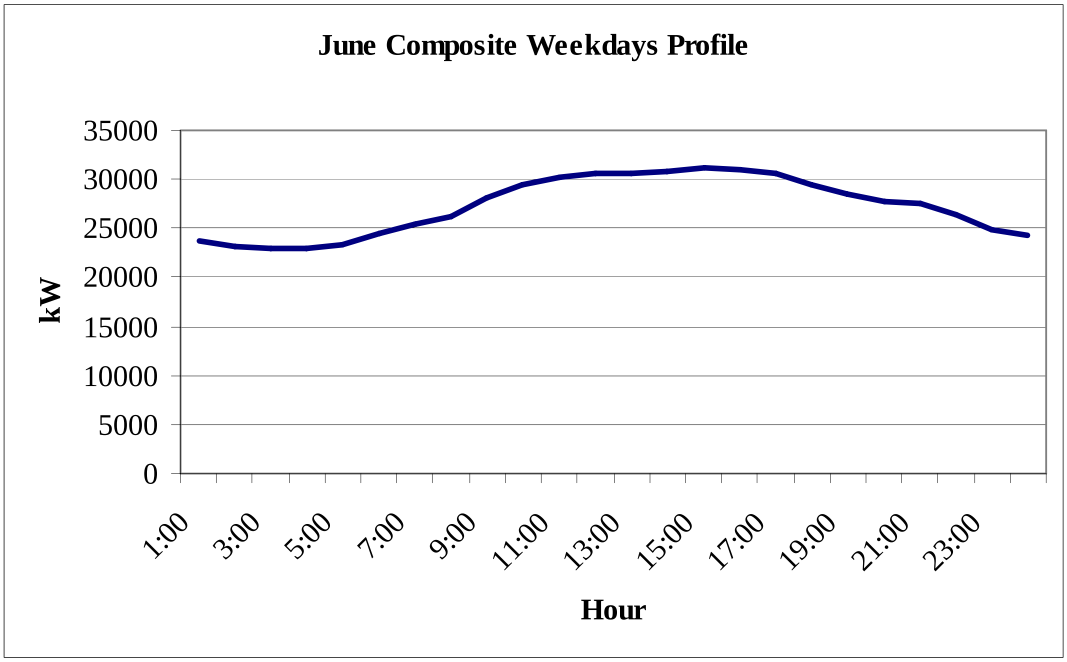

Figure 87. Aggregated Load, Excluding Corpus, June Weekday Average Energy Profile

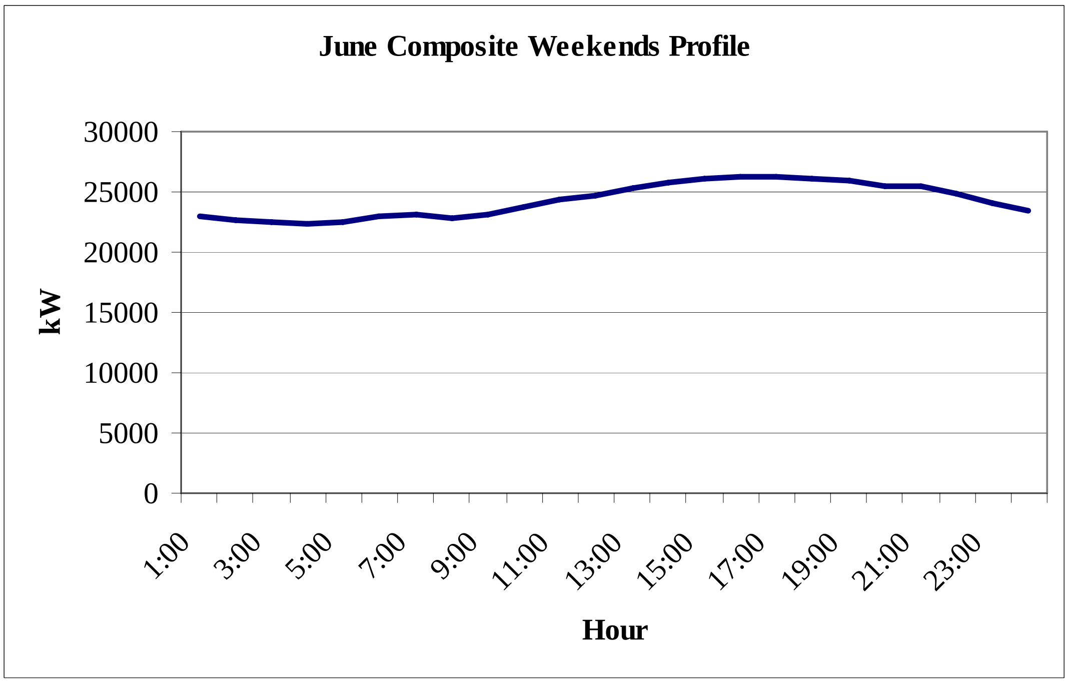

Figure 88. Aggregated Load, Excluding Corpus, June Weekend Average Energy Profile

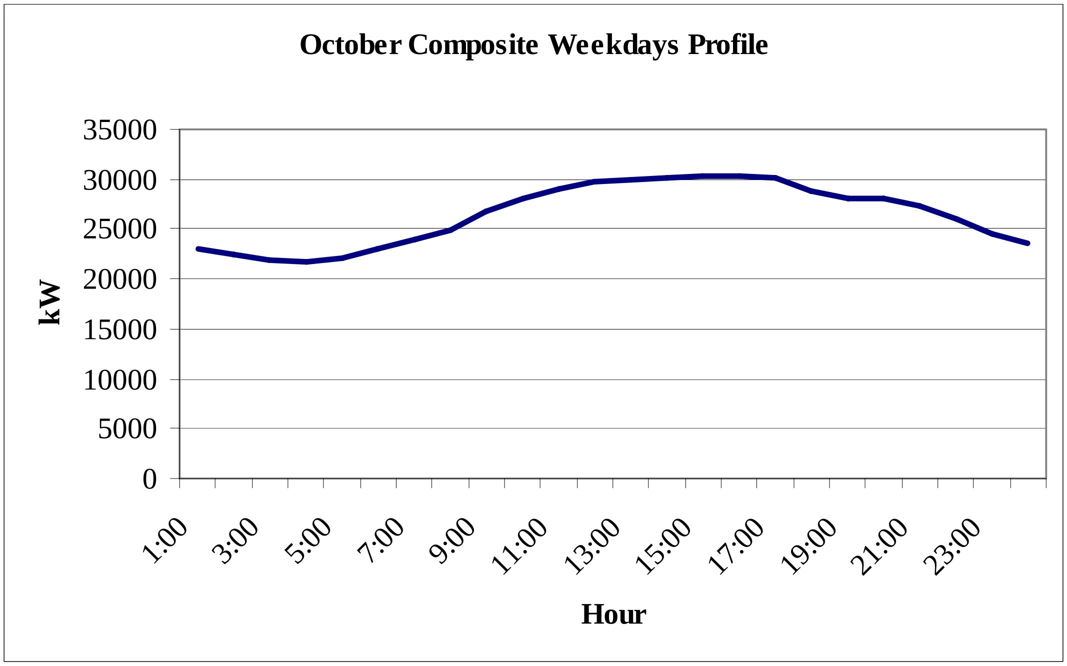

Figure 89. Aggregated Load, Excluding Corpus, October Weekday Average Energy Profile

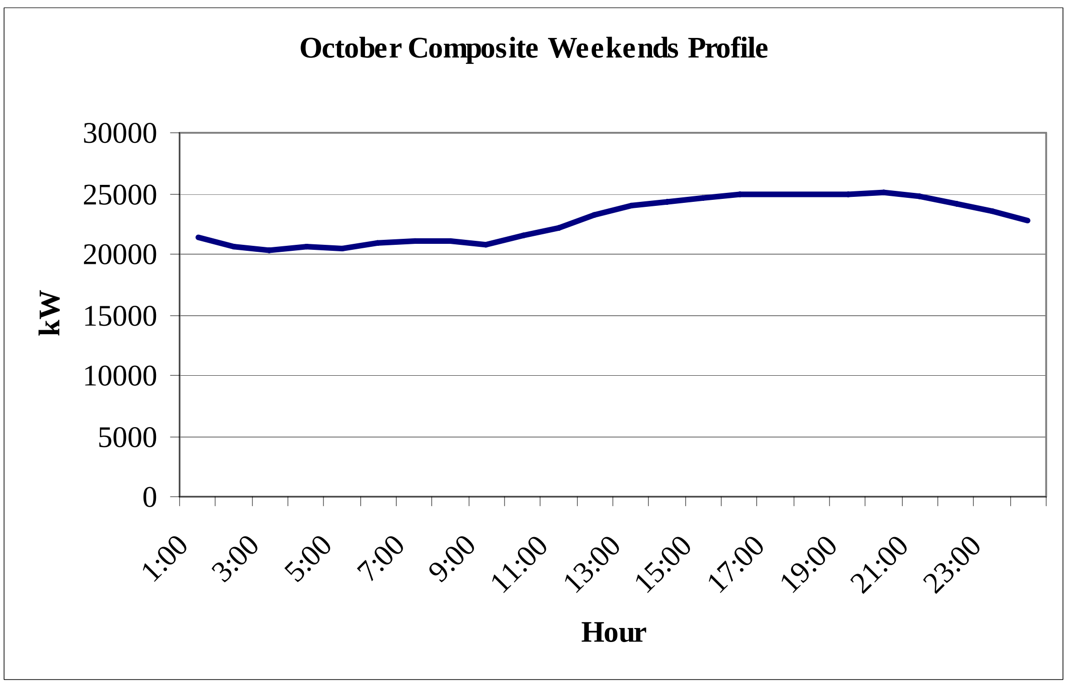

Figure 90. Aggregated Load, Excluding Corpus, October Weekend Average Energy Profile

CHAPTER VIII

REASON FOR THIS STUDY

A. Introduction to Analysis

The Energy Systems Laboratory has served as a technical consultant to the Texas A&M University (TAMU) System on electricity purchases since 2001. A one-year contract was signed for the calendar year 2002, and an eight-month contract was signed for 2003; all based on fixed prices for energy. An electricity contract, based on a fixed energy charge, effective for two years was signed in 2003 for the aggregated load of the TAMU System and several system agencies were added at the end of the fiscal year 2005 contract. In 2005, Stephen Austin University, with 18 accounts located in Nacogdoches, TX, joined TAMUS for the electricity contract for 2005-2006. The added small agency accounts, SFASU accounts and the TAMUS Universities were aggregated into a single purchase, resulting in 183 accounts in the ERCOT North, Northeast, South, West, and Houston areas of Texas.

Eight accounts in the Texas A&M System and the account for Stephen F. Austin University have a peak demand higher than 1000 kW per month, and consume 92% of all the load. Facilities having a peak demand higher than 1000 kW require an IDR (Interval Data Recorder) meter. In the future, these nine accounts will be referred to as IDR meter accounts (ERCOT, 2005b).

The new contract, composed of a fixed energy rate, became effective on August 15 2005, when all meters were changed to Sempra Energy Solutions. Prior to August 15, 2005 Sempra Energy Solutions, except for Stephen F. Austin University, which was served by TXU Energy Services, served all of the IDR meter accounts. Sempra is currently serving all accounts. For clarity purposes, the nine IDR meter accounts will be referred to as IBT, Galveston, Corpus, Kingsville, Laredo, Stephen F. Austin University, Tarleton, Commerce 7, and Commerce 8.

These accounts consume in excess of twenty million dollars of electricity per year, and the electricity consumption increased on November 1, 2005 with the construction of a new facility for the School of Nursing for Prairie View A&M University in Houston's Medical Center area. Considering the significant cost of purchasing electricity by the Texas A&M System, it is very important to take advantage of deregulation and find the most economical price structure.

In order to find the most economical electricity pricing structure, five different pricing scenarios were considered. The bid prices provided by Sempra in 2005 for the tiered price, flat rate, and two different block structures were used, along with the flat rate and the tiered price provided by Sempra for the old contract. Results were given from March 1 to August 31, 2005 for 3 pricing scenarios; the spot market, tiered pricing and the fixed rate. Results were also given from September 1, 2005 to February 28, 2006 for the spot market, tiered pricing, fixed rate and the two previously mentioned block structures. All historical data was provided by Center Point Energy, AEP, and TXU.

B. Scenarios Considered

The first scenario analyzed was the spot market. Within the spot market, the energy is purchased under the Market Clearing Price for Energy, also known as the MCPE, provided by ERCOT. The second scenario consisted of using the fixed electricity rate provided by Sempra. The third and fourth scenario was a 7 X 24 plus a 5 X 16 block structure, and a 5 X 16 block structure respectively. The remainder of the energy was purchased on the MCPE. The last scenario examined was purchasing electricity under the tiered price provided by Sempra.

Under each scenario, total electricity prices for each of the 9 IDR meter accounts were calculated, as well as the total electricity price resulting from the aggregation of loads of all accounts. The evaluation of electricity pricing is based on the IDR accounts, since they consume 92% of the total electricity load. The remaining meters (scalar meters) only lend themselves to fixed pricing scenarios, and have a small influence on the pricing decisions. All accounts are located within Texas.

CHAPTER IX

RESULTS

A. Energy Charges for Aggregated Loads of all 9 IDR Accounts

The results found in this analysis showed buying electricity on the spot market or the day-ahead market would have been the most expensive method to purchase electricity, and the tiered price was the most economical method of purchasing electricity for each individual campus and for the whole system together. See Figure 91 and Figure 92.

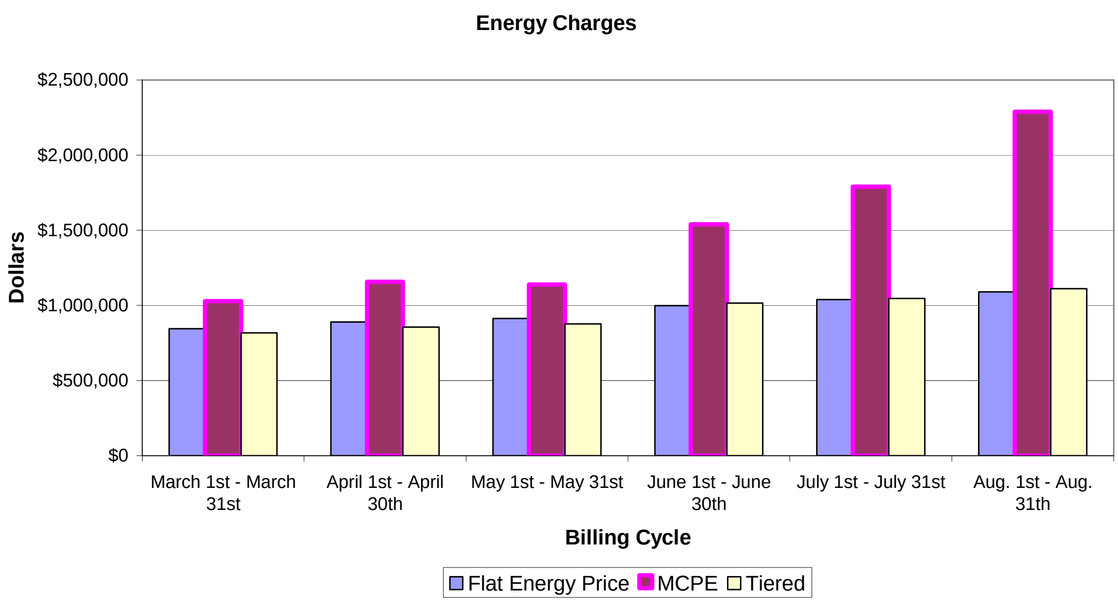

Figure 91. Price Analysis Results of all 9 IDR Aggregated Loads from March 1 to August 31, 2005

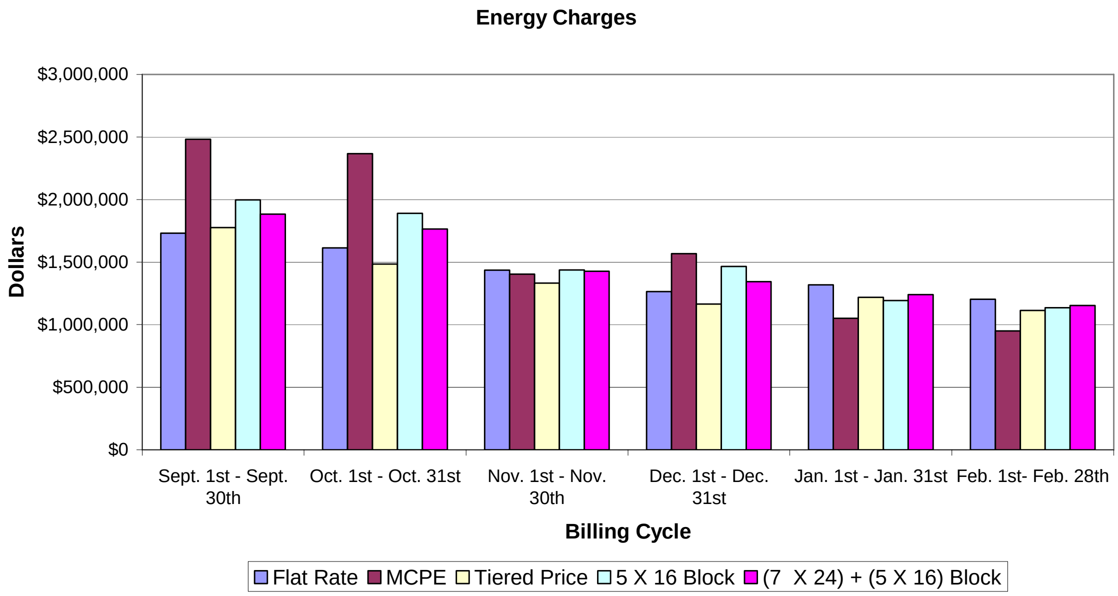

Figure 92. Price Analysis Results of all 9 IDR Aggregated Loads from Sept. 1, 2005 to Feb. 1, 2006

1. Spot Market (MCPE) Analysis

The total cost of purchasing electricity on the spot market from March 1 to August 31, 2005 would have been $8,941,935. The MCPE would have been appealing for the six months prior to signing the new contract if its overall cost would have been 37% lower. The total cost of purchasing electricity on the spot market from September 1, 2005 to February 28, 2006 would have been $9,819,914. In order for the MCPE to be the most economical method from September 1, 2005 to February 28, 2006, it would have had to have been at least 18% lower. The MCPE is very volatile; it can be affected by many factors, including weather conditions, demand, transmission constraints and the price of natural gas. In the latter part of 2005, the MCPE value increased significantly due to hurricanes that affected natural gas production, which increased the price of natural gas. Therefore reductions on the price purchasing on the MCPE cannot be anticipated or expected.

It is important to remember that the MCPE changes every 15 minutes, generally offering low prices during off-peak times and higher prices during on-peak times. The MCPE weighted average of the Texas A&M System and SFA show that the MCPE was higher from 6 am to 10 pm, when the energy consumption was the highest. The MCPE weighted average was the lowest from midnight to 6 am, when the energy consumption was significantly lower. See Figures 93 through 100 for MCPE weighted averages for weekday and weekends for the different ERCOT Zones.

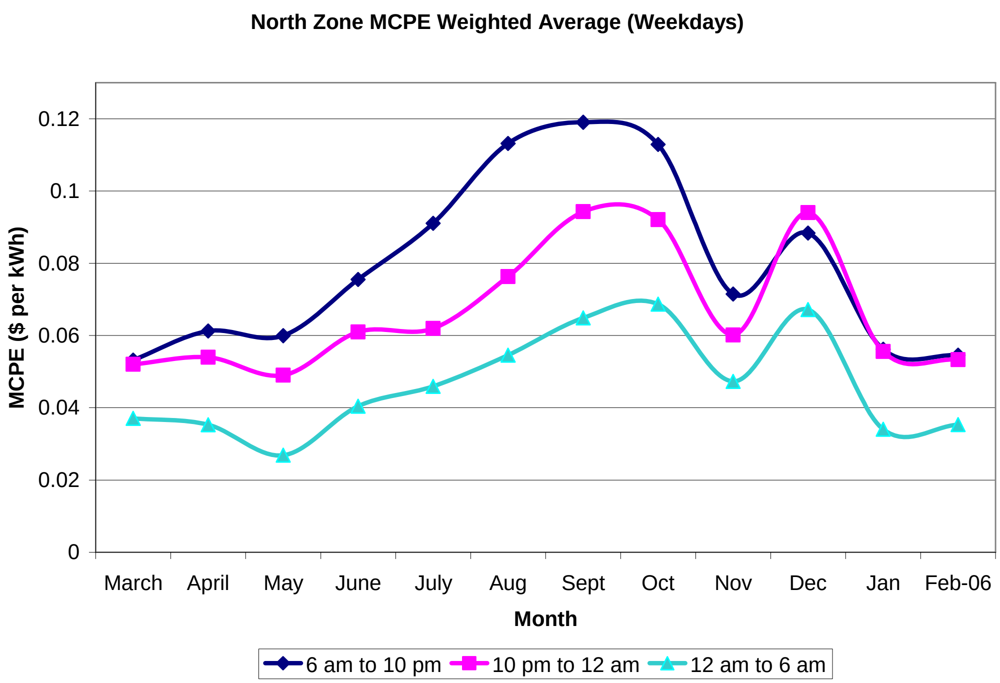

Figure 93. North Zone MCPE Weighted Average (Based on Texas A&M System and SFA)

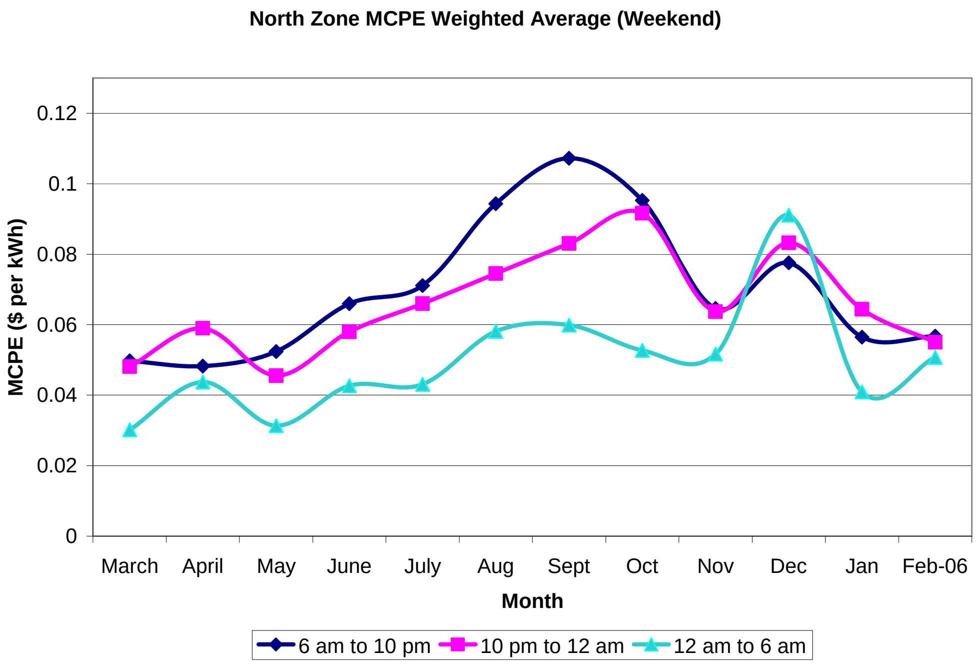

Figure 94 . North Zone MCPE Weighted Average (Based on Texas A&M System and SFA)

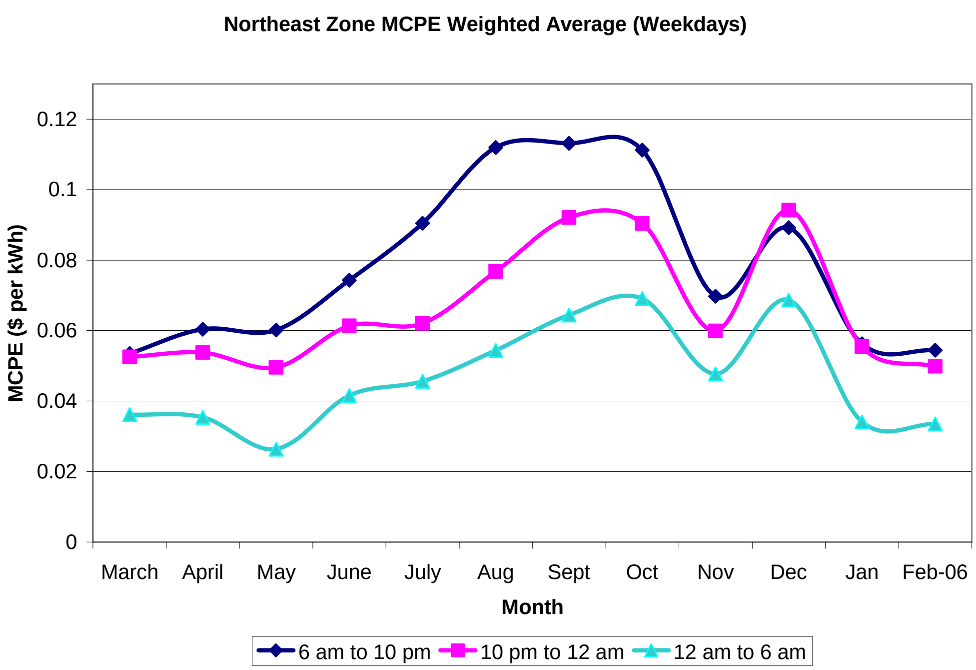

Figure 95. Northeast Zone MCPE Weighted Average (Based on the Texas A&M System and SFA)

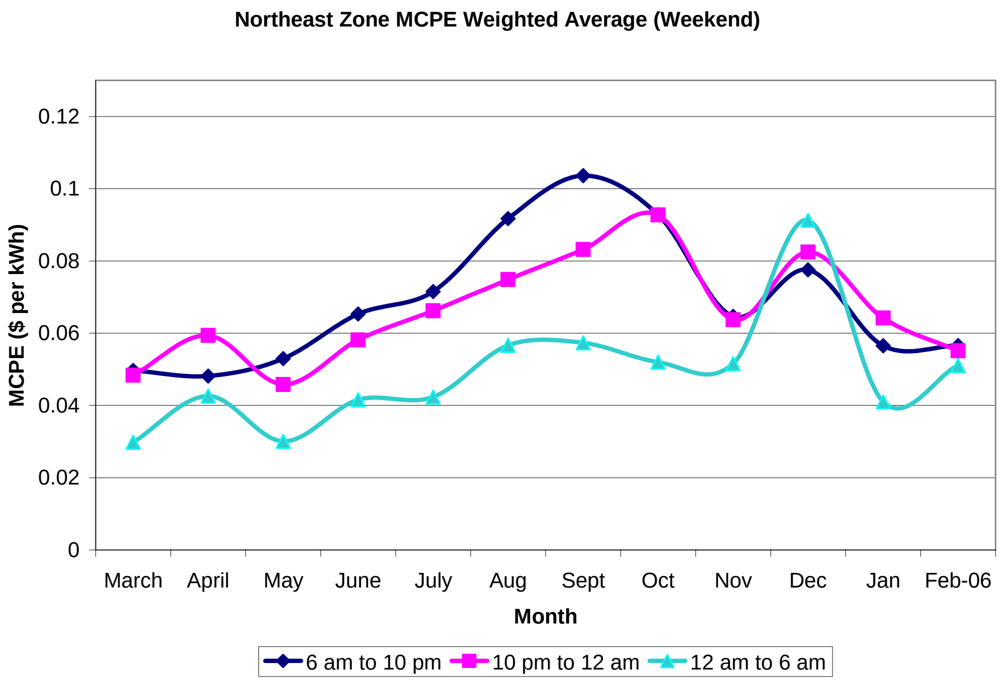

Figure 96. Northeast Zone MCPE Weighted Average (Based on the Texas A&M System and SFA)

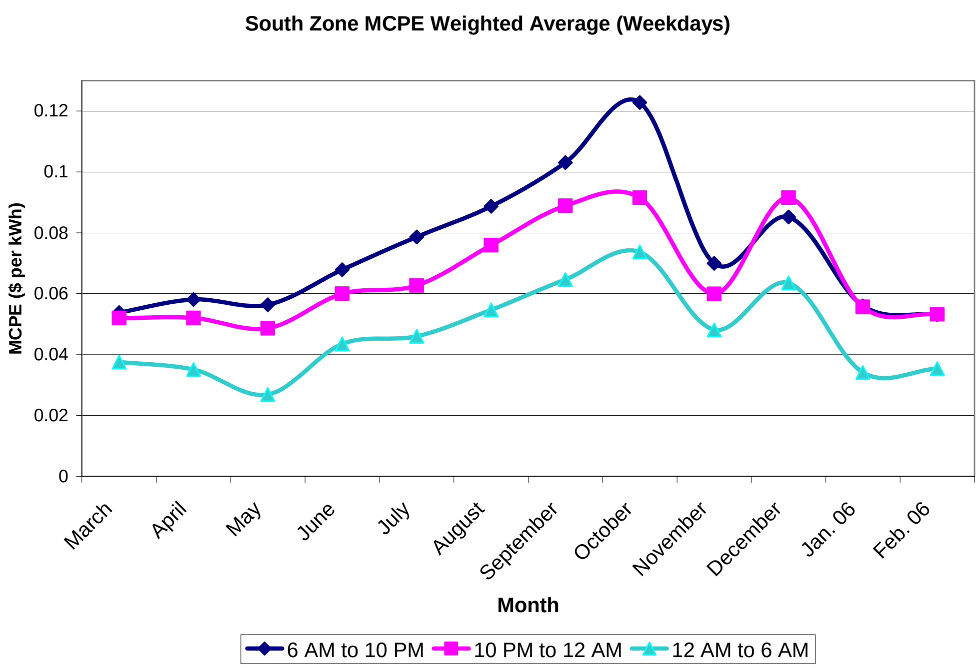

Figure 97. South Zone MCPE Weighted Average (Based on Texas A&M System)

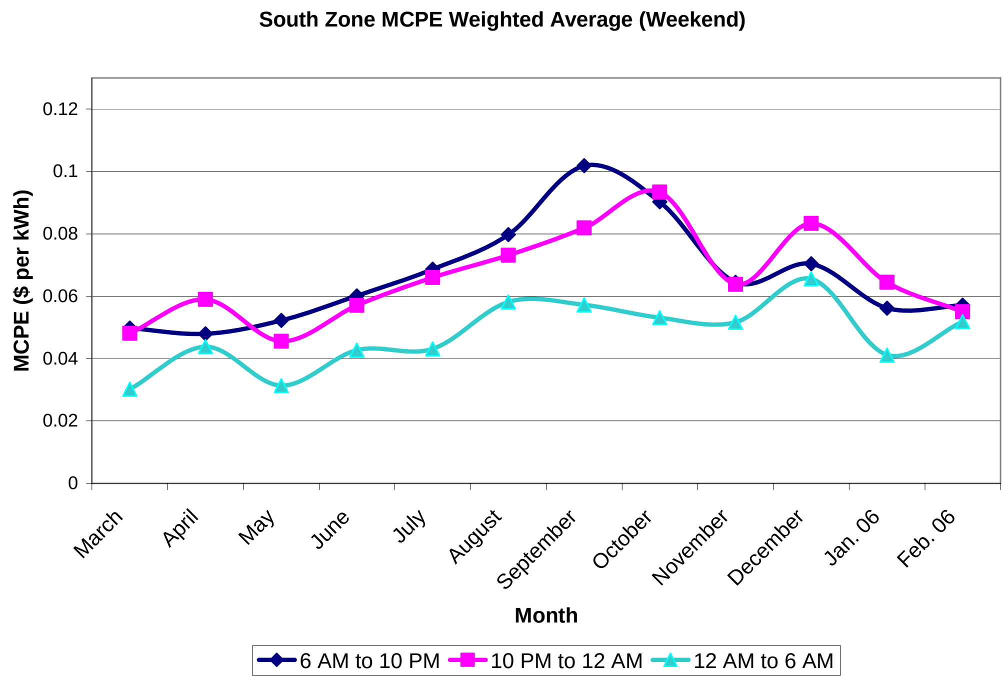

Figure 98. South Zone MCPE Weighted Average (Based on Texas A&M System)

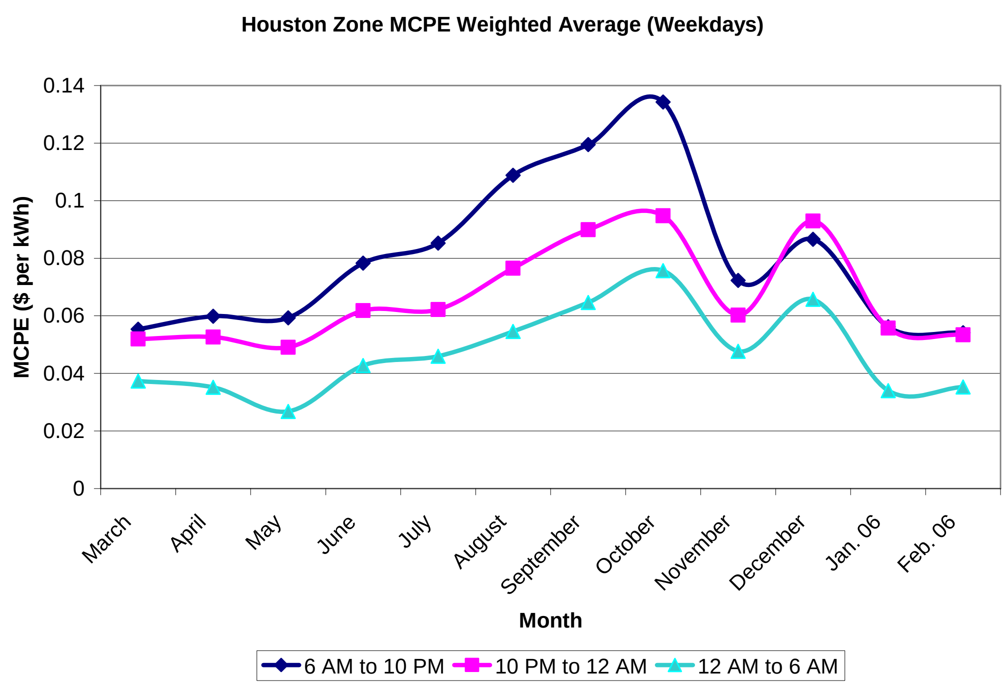

Figure 99. Houston Zone MCPE Weighted Average (Based on Texas A&M System)

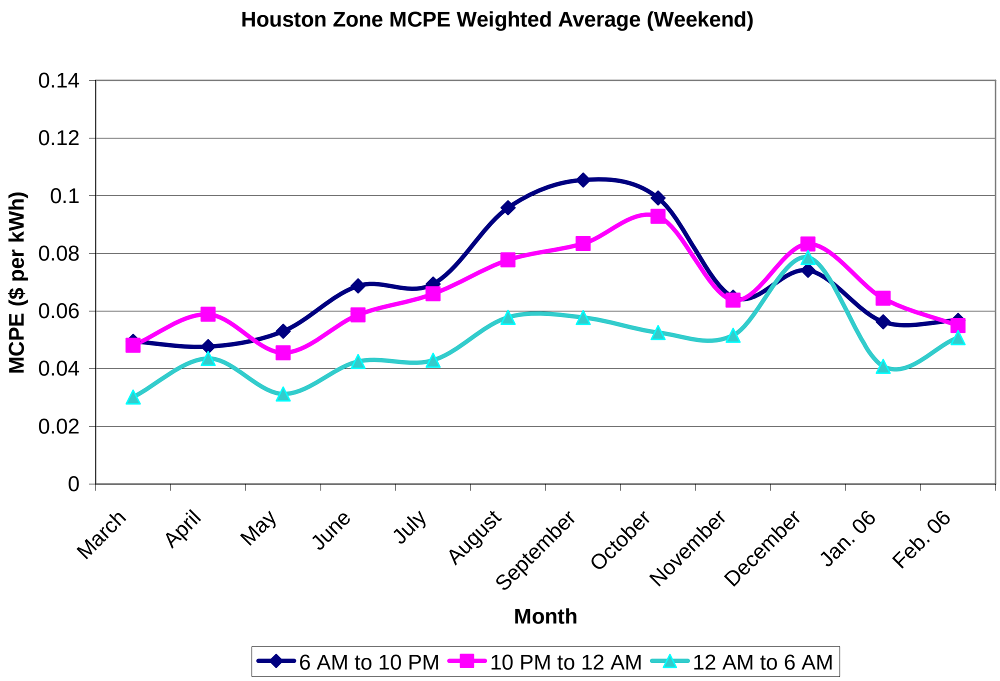

Figure 100. Houston Zone MCPE Weighted Average (Based on Texas A&M System)

The 9 IDR accounts consumed 70% of their load from 6 am to 10 pm, 22% from midnight to 6 am and 8% from 10 pm to midnight. See Figure 101. It is very important to look at the MCPE during on-peak times, even if the monthly average is low, since 70% of the total would be bought from 6 am to 10 pm when MCPE prices are higher and may not reflect the monthly average price.

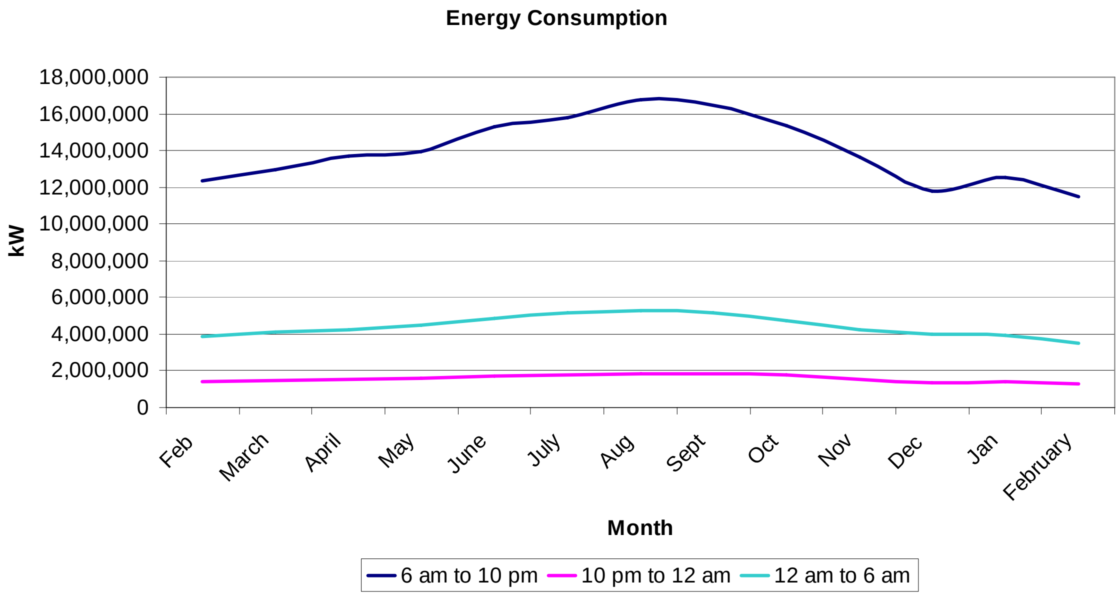

Figure 101. Aggregated Load Consumption of all Facilities

The MCPE was from 22% to 110% higher than the fixed energy rate from March 2005 through August 2005. It was respectively 43%, 47% and 24% higher than the fixed energy rate for the months of September, October and December. The MCPE was 2%, 20% and 21% lower than the fixed energy rate on November 2005 and January and February 2006, respectively. The lowest monthly MCPE weighted average price from March 2005 to February 2006, would have been $.0555 per kWh on March 2005. The highest monthly weighted average price would have been $.1082 per kWh on October 2005. The MCPE weighted average from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006 was $.0706 and $.0845 per kWh respectively. It dropped by 33% in November 2005 (from a monthly average value of $.1082 to $.0721 per kWh), 36% in January (from a monthly average value of $.09124 to $.05874 per kWh) and 1% in February (from a monthly average value of $.05874 to $.05835per kWh).

In the first two months of 2006, the overall MCPE value decreased approximately 36%, making it 20% lower than the fixed rate of energy ($250,000 lower for each month compared to the fixed price monthly energy cost) and 14% lower than the tiered price (approximately $165,000 lower for each month compared to purchasing electricity under the tiered price). For the first two months of 2006, it was very appealing and the most economical method of purchasing electricity compared to the other price structures. In November 2005 the MCPE at $.0721 per kWh, was 2.3% lower (about $32,000) than the fixed energy price, but it was 5.4% higher (about $72,000) than the tiered energy price. Having a low MCPE value for three months out of twelve did not compensate for the high prices of the MCPE for most of the year of 2005.

Purchasing electricity on the spot market from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006 would have had generated costs of 55% and 15% higher, respectively, than on the fixed energy rate with Sempra. It would have had generated costs of 56% and 21% higher, respectively, than purchasing electricity on the tiered price from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006. Overall, if the electricity would have been purchased on the MCPE from March 1, 2005 to February 28, 2006, an additional $4,420,280 would have had to have been paid; approximately 31% higher than purchasing electricity on the fixed rate. Purchasing electricity on the MCPE would be $4,951,289 more expensive, around 36% higher, than purchasing electricity on the tiered price.

For the MCPE to have been appealing, its overall price would have to be decreased by at least 27% for the whole period of the contract. Buying electricity on the spot market is the most risky method to purchase electricity. Prices can reach extremely high prices for events that cannot be anticipated. Looking at monthly averages, the MCPE in 2005 increased 6% to 126% compared to the value it had in February 2005. The MCPE could be the most economical method for purchasing electricity in the future if the low prices of the first two months of 2006 remain; however, due to the predicted hurricane season and the political scene, the MCPE prices most likely will not remain low for the rest of the year.

The MCPE was lower due to good weather conditions in January that decreased demand and increased the levels of storage of natural gas, thus decreasing the natural gas prices (See Figure 102). This scenario will change as summer begins and more electricity is required for cooling. During hurricane season, from June to November, natural gas production may be affected by a hurricane, thus increasing electricity prices. Figure 102 shows the price variation of natural gas and the impact on the MCPE monthly average prices.

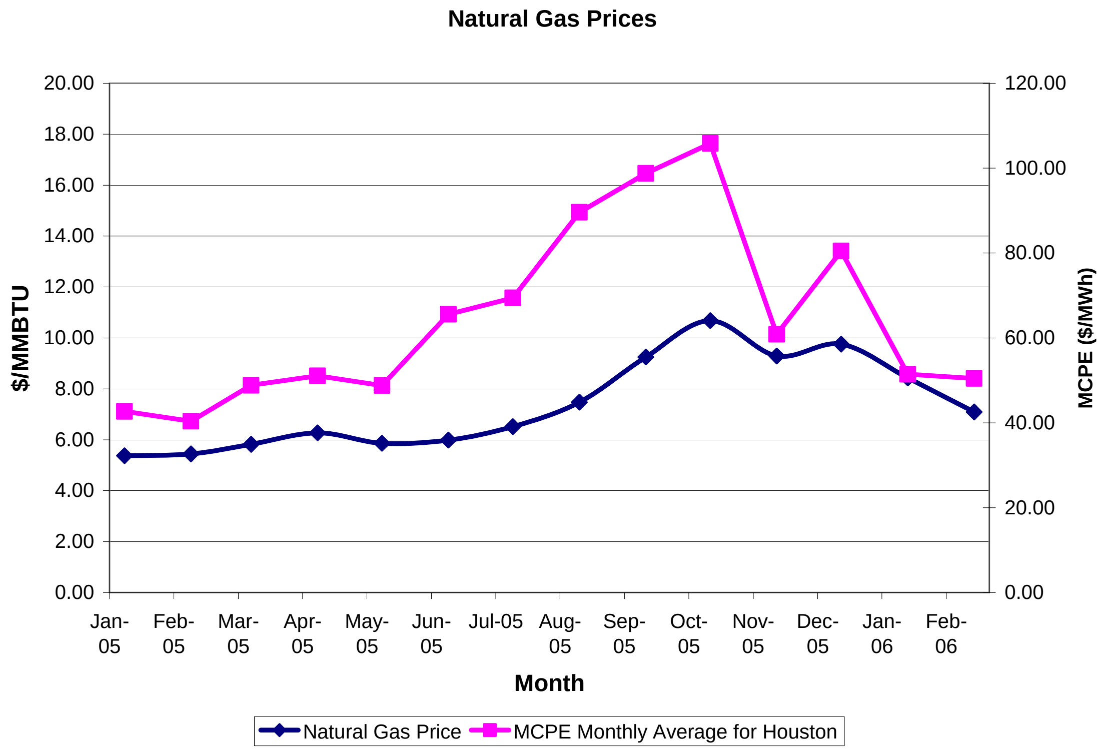

Figure 102. Natural Gas Prices vs. Electricity Prices

2. RFP-Requested Block Structure (7 X 24 + 5 X 16) plus MCPE Pricing

Under the second electricity pricing scenario, a block of 7 X 24 plus a 5 X 16 block, the total costs of electricity were found to be higher than the energy costs under the fixed rate and the tiered price. Under the block structure, some energy has to be purchased on the spot market to meet the energy demand. The energy charge increased significantly as MCPE prices were high. The benefit of the block structure is its advantage of avoiding some of the risk of purchasing electricity on the spot market. The customer can decide the amount of electricity to purchase at a fixed price, limiting the amount of electricity to be purchased on the MCPE.

For any of the two block structures, there are three important facts: the energy charge for the electricity being bought on the block, the MCPE price and the amount of energy purchased on the spot market. This method of purchasing electricity can be beneficial or disadvantageous depending on the MCPE price and the amount of energy one decides to risk on the spot market. If the MCPE is high even if the energy price for the block is economical, it can result in higher energy prices. If the MCPE is low and the amount of energy to be bought on the spot market is a significant portion of your purchase, it becomes a very economical method to purchase electricity. This type of structure is directly affected by MCPE prices.

Table 16 gives information of the first block structure requested in the fiscal year 2006 RFP. The energy charge of the electricity ($.0712/kWh) bought within this block structure was cheaper than the fixed price of electricity ($.07375/kWh) of the contract. However, due to the high costs of the MCPE, purchasing electricity using this method would have been more expensive than purchasing electricity at a fixed price. The total cost of purchasing electricity on this block structure from September 1, 2005 to February 28, 2006 would have been $8,811,022. The total cost difference of purchasing electricity on the block structure and the fixed price was $244,404 (2.85% higher than the total costs on the fixed price). The block structure was $721,896 (8.9%) higher than the tiered price. See table 17.

Table 17. First Block Structure

7 X 24 (MW)											
Aug-05	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	**Jul-06**
19	19	19	19	19	19	19	19	20	20	20	20
5 X 16 (MW) (Weekdays)											
9	9	8	3	0	0	4	4	5	6	8	9
TOTAL MW on Peak Hours											
28	28	27	22	19	19	23	23	25	26	28	29

Table 18. First Block Structure Percentage of Energy Purchased On-Peak vs. Off-Peak

	ON PEAK	**OFF PEAK**
Sep-05	56%	44%
Oct-05	55%	45%
Nov-05	72%	28%
Dec-05	78%	22%
Jan-06	82%	18%
Feb-06	70%	30%

The energy cost under this type of block structure was $1,008,892 less (10% lower) than purchasing all the electricity on the spot market. At the same time it was $304,868 less (3% lower) than purchasing electricity on the third scenario, the 5 X 16 block structure.

In order for the 7 X 24 + 5 X 16 block structure to be the most economical method to purchase electricity from September 1, 2005 to February 28, 2006, the overall MCPE price would have had to have been at least 35% lower. Assuming the low MCPE prices at the beginning of 2006 could not decrease any further, the MCPE values of 2005 would have had to have been 42% lower, around $.063 per kWh in September, $.069 per kWh in October, $.046 per kWh in November, and $.061 per kWh in December. With an adverse hurricane season and/or harsh climate conditions, these MCPE values would not be realistic.

Increasing or decreasing the sizes of the blocks (either the 7 X 24 or the 5 X 16) by 1MW or more would be beneficial depending on the MCPE price. For the months of November, January and February decreasing the amount of energy purchased on the MCPE price would have been favorable because of the low costs of the MCPE on those months. However, for most months in 2005 it would have been advantageous to increase the amount of energy to be purchased in the block structure and avoid the high costs of the MCPE, as noted in Table 19.

Table 19. First Block Structure (7 X 24 + 5 X 16) Results

	Sept	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**
% Energy in Excess	0.33%	0.97%	0.40%	1.02%	0.09%	1.62%
% Energy in MCPE	23.52%	17.96%	22.64%	18.43%	21.04%	12.15%
% Energy in Block	76.48%	82.04%	77.36%	81.57%	78.96%	87.85%
% Costs of MCPE	31.95%	26.82%	24.56%	25.03%	6.22%	10.20%
% Costs of Block Energy	68.05%	73.18%	75.44%	74.97%	93.78%	89.80%
Block Charge ($/kWh)	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
MCPE ($/kWh)	$0.11	$0.12	$0.08	$0.11	$0.06	$0.06
kWh	23,536,990	22,091,225	19,546,068	17,329,783	17,902,821	16,574,303
Total Energy Charge	$1,883,289	$1,763,135	$1,427,004	$1,342,502	$1,240,743	$1,154,350

It is very important to know the time of day in which it was needed to purchase electricity to meet the demand. The majority of the energy purchased on the MCPE took place on ERCOT's peak hours (6 am to 10 pm), thus purchasing electricity on the highest MCPE prices (See Table 17).

The MCPE value cannot be anticipated, preventing one from knowing exactly the block size that would give the lowest energy charge. The block size has to be determined according to the risk that the end-use customer wants to have. The original block structure is noted on Table 16.

2.1 Revised Block Structure (7 X 24 plus 5 X 16)

Three factors have to be considered when changing the block size. First of all, the energy charge within the block will increase when the total amount of energy to be purchased on-peak is modified. The amount of energy to be purchased each hour in the block structure varies from 19 to 29 MW depending on the month. Increasing the amount of energy to be purchased for each hour above 25 or 30 MW could increase the energy charge within the block. In order to maintain the same energy price within the block structure, the block size, for analysis purposes, will not be increased by more than 2 MW. The second factor to consider is the amount of energy that one wants to risk on the spot market, and the third factor is the amount of excess energy that would be purchased if the block size were increased.

The MCPE values can increase significantly the energy charges of the block structure; therefore, the amount of energy to be purchased on the MCPE will be kept under 25%, limiting the risk of increasing cost. Having this in mind, the limit to decrease the block size on peak (5 X 16 Block) would be 1 MW, increasing the amount of energy to be purchased on the MCPE to 21%. The limit to decrease the energy on the 7 X 24 block would also be 1 MW, increasing the amount of energy to be purchased on the MCPE to 23%. In order to avoid increasing the amount of energy to be purchased on the MCPE to more than 25%, only one block can decrease its size.

Finally, the amount of excess energy to be purchased is desirable to be lower than 2% to avoid increasing costs by purchasing large amounts of electricity that is not used. Increasing the amount of energy to be purchased on the 5 X 16 block by 1 MW or 2 MW, would increase the excess energy from .71% to 1.14% and 1.72% respectively. Increasing the amount of energy to be purchased on the 7 X 24 block by 1 MW or 2 MW, would increase the excess energy from .71% to 1.26% and 2.05% respectively.

Increasing the 7 X 24 block structure by more than 1 MW would increase the amount of energy to be purchased that is not needed, increasing costs and removing any savings obtained from avoiding buying energy on the MCPE. Under high MCPE prices increasing the 7 X 24 block structure by 1 MW would be $4,000 cheaper from September 1, 2005 to February 28, 2006 compared to the original size. However, if the 7 X 24 block structure was increased by 2 MW, the cost from September 1, 2005 to February 28, 2006, compared to the original size, would increase $10,000. Increasing the 7 X 24 block size by 2 MW increases the percentage of energy purchased that is not consumed from 0.71% to 2.05%, thus increasing the total cost. Decreasing the size of the 7 X 24 block by 1 MW or more would increase the energy costs by at least $17,000 from September 1, 2005 to February 28, 2006.

Increasing the 5 X 16 block structure by 1 MW would cost $17,000 less from September 1, 2005 to February 28, 2006 compared to the original size. If the 5 X 16 block structure was increased by 2 MW, the cost from September 1, 2005 to February 28, 2006, compared to the original size, would decrease $20,000. Increasing the 5 X 16 block by 2 MW generates more savings than increasing the block size by 1 MW because the amount of energy purchased on the MCPE is lower by increasing the block size by 2 MW, thus avoiding the high cost of purchasing electricity on the MCPE. Increasing the 5 X 16 block size by 3 MW or more increases the percentage of energy purchased that is not consumed, increasing the total cost. Decreasing the size of the 5 X 16 block by 1 MW or more would increase the energy costs by at least $27,000 from September 1, 2005 to February 28, 2006.

In determining if increasing or decreasing the block size would be beneficial, different types of scenarios were studied for different types of structures. The first scenario was one in which the MCPE price for 2005 was 10% lower. The second scenario was one in which the MCPE price decreased 10% from September 1, 2005 to February 28, 2006. The third scenario was one in which the MCPE price for 2005 was 20% lower. The fourth scenario was one in which the MCPE price decreased 20% from September 1, 2005 to February 28, 2006. The fifth scenario was one in which the MCPE decreased 10% every other month from September 1, 2005 to February 28, 2006. The sixth scenario was one in which the MCPE decreased 20% every other month from September 1, 2005 to February 28, 2006. The seventh scenario was one in which the MCPE price increased 10% from September 1, 2005 to February 28, 2006. The eighth scenario was one in which the MCPE price increased 20% from September 1, 2005 to February 28, 2006. The ninth scenario was one in which the MCPE increased 10% every other month from September 1, 2005 to February 28, 2006. The tenth scenario was one in which the MCPE increased 20% every other month from September 1, 2005 to February 28, 2006. The last scenario was one in which the MCPE had the same prices from 2005 to 2006. The limits to decrease and increase the MPCE were chosen to be by 10% and 20% in order to be conservative in the calculations. The results from each scenario are included in Appendix D.

Increasing the block sizes by 2 MW on-peak (that is on the 5 X 16 block structure) gave savings of less than 1.2%, less than $110,000 from September 1, 2005 to February 28, 2006, in 5 out of 11 scenarios, compared to the original size under the same scenarios. The savings were achieved when the MCPE had a high value (20% higher than the actual MCPE values from 2005 to 2006, averaging $.108 per kWh). Increasing the block sizes by 2 MW could also increase the energy costs by less than 0.8%, around $65,000 from September 1, 2005 to February 28, 2006. Decreasing the 5 X 16 block size by 2 MW gave losses up to 1.3% for 10 scenarios out of 11, from $2,000 to $130,000 from September 1, 2005 to February 28, 2006. It gave savings when the MCPE price was 20% lower than its overall value, around $.08 kWh a value that most likely will not remain consecutive for 6 months under harsh weather conditions such as a dry hot summer, a cold winter, hurricanes, etc. Under all scenarios and for all block sizes, the block structure pricing was higher than the tiered, and it only reduced costs compared to the fixed price under the scenario of having a 20% decrease in value of the MCPE ($.08 per kWh).

Increasing the block sizes by 1MW from 6 am to 10 pm resulted in savings in 8 out of 11 scenarios. The maximum savings achieved under different scenarios was around $62,000 dollars, about 0.7% compared to the original cost structure under the same scenarios. Increasing the block size for the 7 X 24 block by 1 MW resulted in savings for 7 scenarios out of 11. The maximum savings achieved under different scenarios was around $66,000, less than 1% compared to the original structure. By increasing the size of the 7 X 24 block, the energy costs could increase up to $60,000 if the MCPE price increased by 20%. Decreasing the block size by 1 MW either on peak hours or 24 hours a day could result in an increase of energy costs up to $82,000, with savings up to $47,000, less than 1%.

Overall, changing the block sizes did not result in significant savings that could guarantee savings for more than 2%; therefore, changing the block sizes was not found to have any significant benefit. It verified that the original block sizes in the RFP were correctly sized and were very close to the optimum scenario. Although increasing the sizes of the blocks may be beneficial under different scenarios, it takes away the possibilities of purchasing electricity on the low MCPE prices by reducing the amount of energy to be purchased on the MCPE price. The original block size had around 20% of energy purchased on the MCPE price. Having about 20% of the total energy on the MCPE, decreases the risk of having to pay significant high energy charges while giving the opportunity to benefit from low MCPE prices.

Finally, the option of selling back the excess energy to the energy provider under the same price of the energy bought within the block ($.0712 per kWh) was assumed. It was found that although the excess energy increases the costs and therefore limits the incremental of increase of energy in the block size, it is still too small to decrease the total cost of energy by more than $60,000, remaining at least $180,000 above the cost of purchasing electricity on the fixed or tiered price.

3. Second Block Structure (5 X 16) with MCPE Pricing

The second block structure, the 5 X 16, had higher electricity costs than the previously mentioned block structure. For the size of this block structure see Table 20.

Table 20. Second Block Structure

5 X 16 (MW)											
Aug-05	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	**Jul-06**
28	27	22	19	19	23	23	25	26	28	29	30

In this purchasing scenario, the energy is purchased on the peak (weekdays from 6 am to 10 pm). From September 1, 2005 to February 28, 2006, would have cost $9,115,890, around 6.4% and 12.7% higher, respectively, than the energy costs under the fixed price and the tiered price. The first reason was the higher cost for energy ($.0782/kWh) within the block compared to any other method, excluding the spot market. The MCPE would have had to be 34% lower than the price it had from September to December 2005, or about $.058 per kWh, for this block approach to be cheaper. The MCPE cost for the months of January and February were more than 20%

lower then the MCPE cost in December; therefore the MCPE price for January and February was not considered to be able to decrease any further.

From September 1, 2005 to February 28, 2006, this method was $549,000 higher than the fixed energy charge, and around $1,026,000 higher than the costs on the tiered price. Increasing or decreasing the size of the block by 1 or 2 MW did not give more than a couple of hundred of dollars in savings due to the high prices of the energy within the block.

Under this block structure more than 40% of the energy was purchased on the block structure, making the total energy charges higher compared to the costs under the fixed rate and the tiered price. See Table 21. The majority of the energy purchased on the MCPE was purchased during off-peak time, therefore purchasing electricity at lower MCPE prices. See Table 22. Increasing the size of the block would not make it more appealing since the energy charge at best would stay the same, remaining higher than the fixed or tiered price. Decreasing the amount of energy of the blocks would increase the already high risk of purchasing electricity on the spot market, since over 40% of the total load would be purchased on the spot market. No matter whether the block increased or decreased in size, the energy cost remains high compared to other methods.

Table 21. Second Block Structure Results

	Sept	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**
% Energy in Excess	0.33%	0.95%	0.40%	0.66%	0.05%	1.34%
% Energy in MCPE	42.90%	39.37%	45.97%	45.43%	47.34%	37.66%
% Energy in Block	57.10%	60.63%	54.03%	54.57%	52.66%	62.34%
% Costs of MCPE	47.38%	44.59%	42.58%	49.69%	5.38%	29.06%
% Costs of Block Energy	52.62%	55.41%	57.42%	50.31%	94.62%	70.94%
Block Charge ($/kWh)	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
MCPE ($/kWh)	$0.09	$0.10	$0.07	$0.09	$0.05	$0.05
kWh	23,536,990	22,087,108	19,546,068	17,269,676	17,894,276	16,527,939
Total Energy Charge	$1,996,673	$1,889,261	$1,437,622	$1,464,338	$1,192,596	$1,135,401

Table 22. Second Block Structure Percentage of Energy Purchased On-Peak vs. Off-Peak

	ON PEAK	**OFF PEAK**
Sep-05	31%	69%
Oct-05	25%	75%
Nov-05	35%	65%
Dec-05	32%	68%
Jan-06	37%	63%
Feb-06	23%	77%

4. Tiered Energy Structure

The tiered energy price was very close to the fixed energy price for the first half of 2005 due to various factors. First, the schedule for on and off-peak periods was from 6 am to 10 pm and from 10 pm to 6 am respectively; therefore, there were 88 hours

(52.38% of weekly hours) of energy consumption during off-peak time rates and 80 hours (47.62% of weekly hours) of energy consumption during on peak time rates. Secondly due to the on and off-peak schedule, the energy consumption during off-peak time was 4% lower than the consumption during on-peak time. See Figure 103.

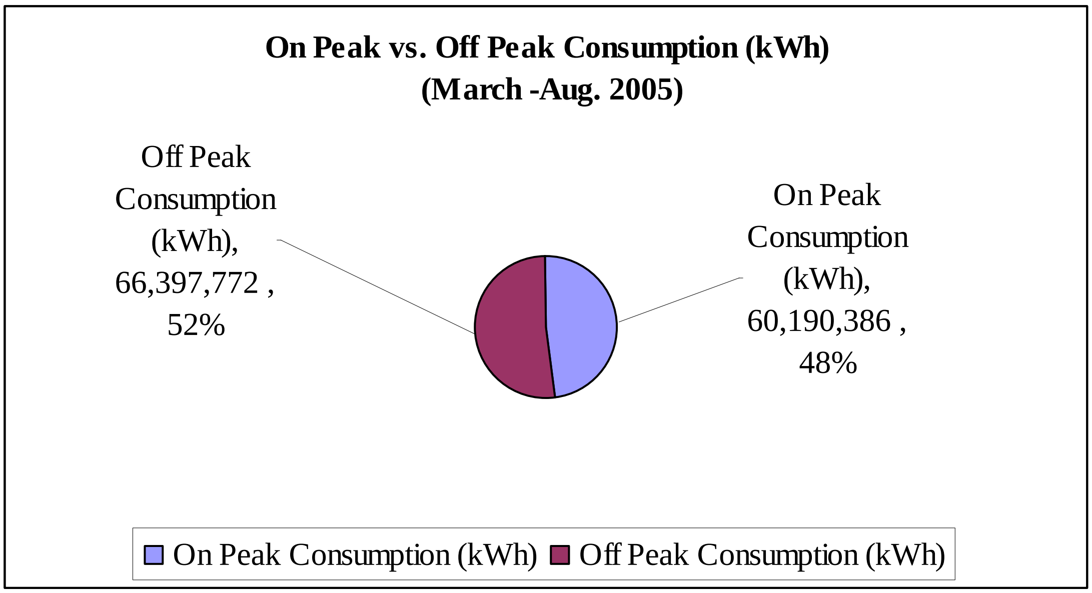

Figure 103. On-peak Consumption vs. Off-Peak Consumption from March 1 to August 31, 2005

From March 1 to August 31, 2005, the total difference between purchasing electricity on the tiered energy price and the fixed energy price was about $54,000, about 1% lower than the total cost of purchasing electricity on the fixed price. See Figure 104.

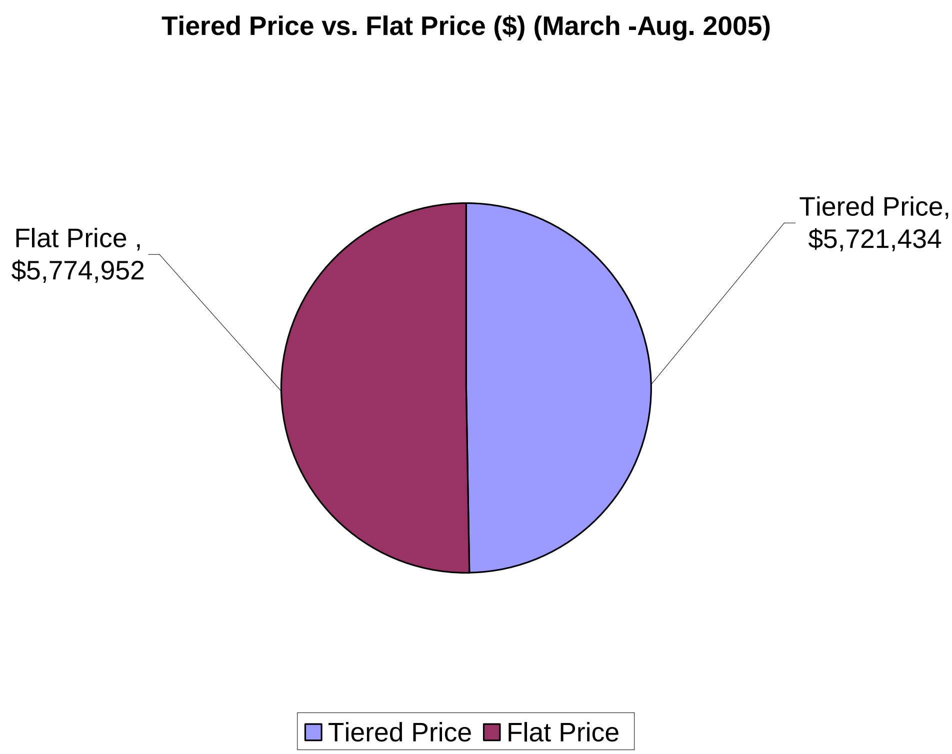

Figure 104. Tiered Price vs. Flat Price from March 1 to August 31, 2005

During off-peak time, the tiered price showed a more economical price than the flat price (see Figure 105); however, during on-peak times, the flat price offered a more economical price (see Figure 106). Overall, due to the slightly higher energy consumption during off-peak time, a lower energy price could have been achieved under the tiered price structure.

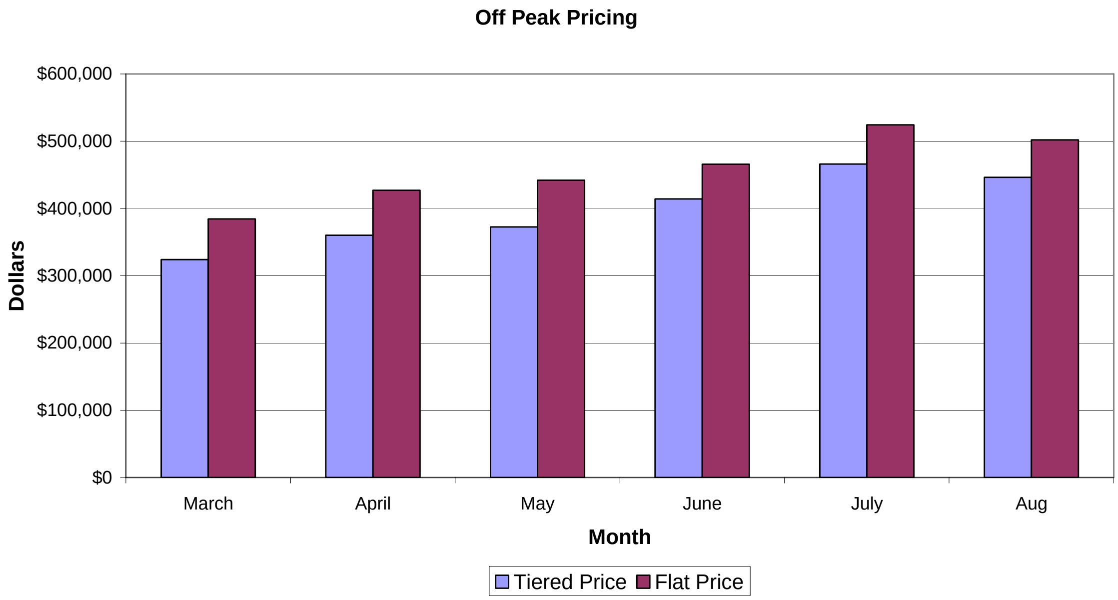

Figure 105. Tiered Price Off-Peak vs. Flat Price from March 1 to August 31, 2005

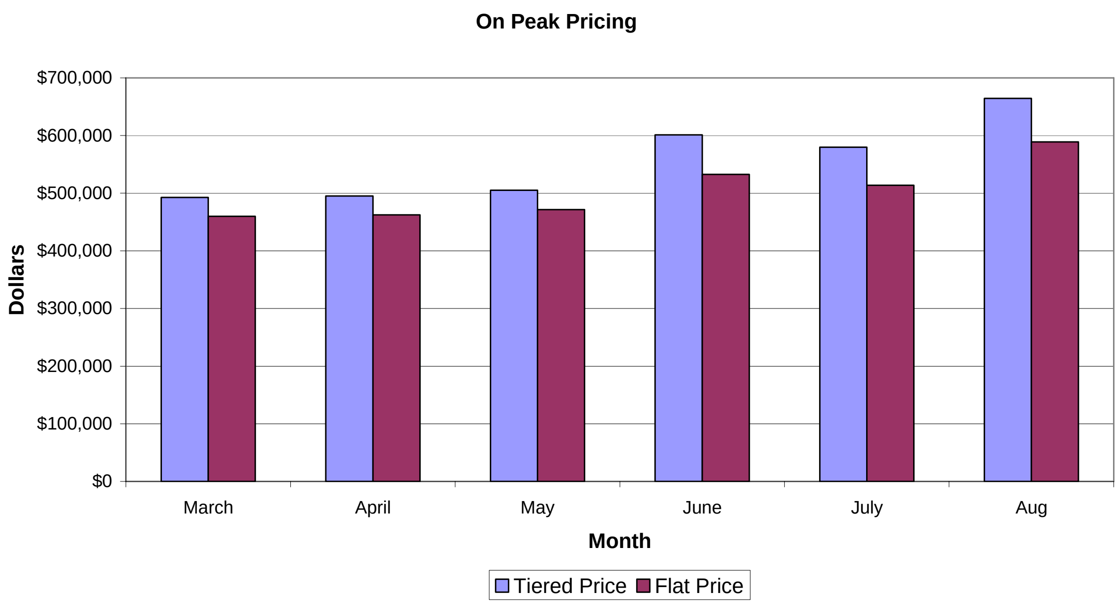

Figure 106. Tiered Price On-Peak vs. Flat Price from March 1 to August 31, 2005

From September 1st, 2005 to February 28th, 2006, there was a greater difference of purchasing electricity on the tiered energy price than on the fixed energy price. The schedule for on and off-peak periods was changed to 6 am to 7 pm and from 7 pm to 6 am respectively; therefore, there were 113 hours (67.27%) of energy consumption during off-peak rates and 55 hours (32.73%) of energy consumption during on-peak rates. Secondly due to the on and off-peak schedule, the energy consumption during on-peak time was 14% lower than the consumption during off-peak time. See Figure 107. Therefore, the total difference between purchasing electricity on the tiered energy price and the fixed energy price was about $480,000. See Figure 108. Purchasing electricity on the tiered price was 5.6% lower than on the fixed rate.

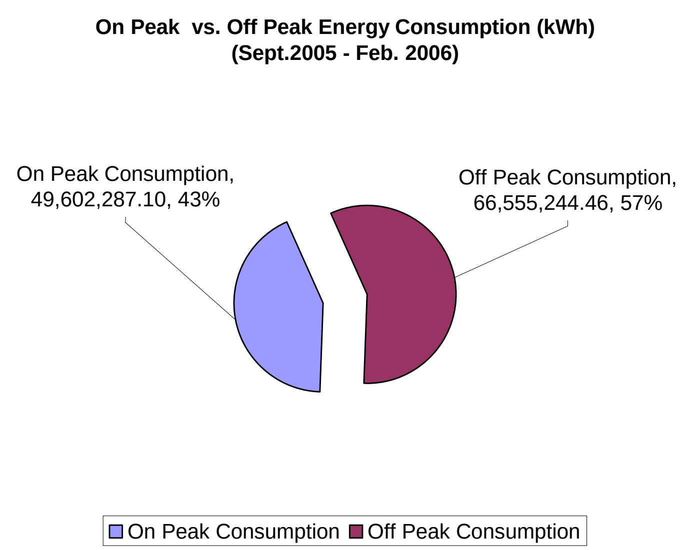

Figure 107. On-Peak vs. Off-Peak Consumption from September 1, 2005 to February 28, 2006

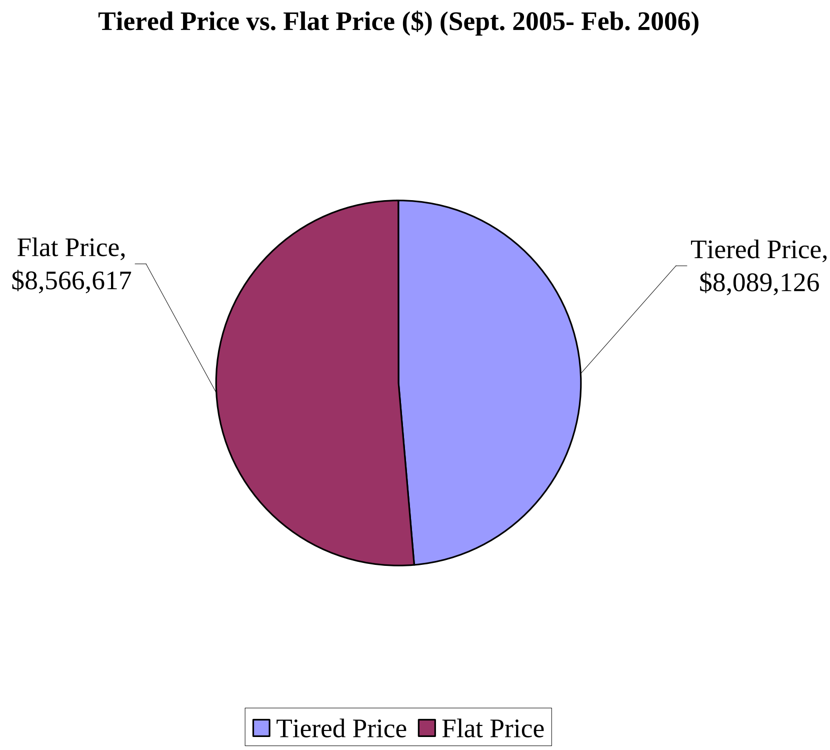

Figure 108. Tiered Price vs. Flat Price from September 1, 2005 to February 28, 2006

Purchasing electricity on the flat rate during peak times was more economical, but it was more expensive than the tiered price during off-peak time (See Figure 109 & Figure 110). The energy consumption during off-peak time was higher, giving the opportunity for the tiered price to provide a more economical energy rate.

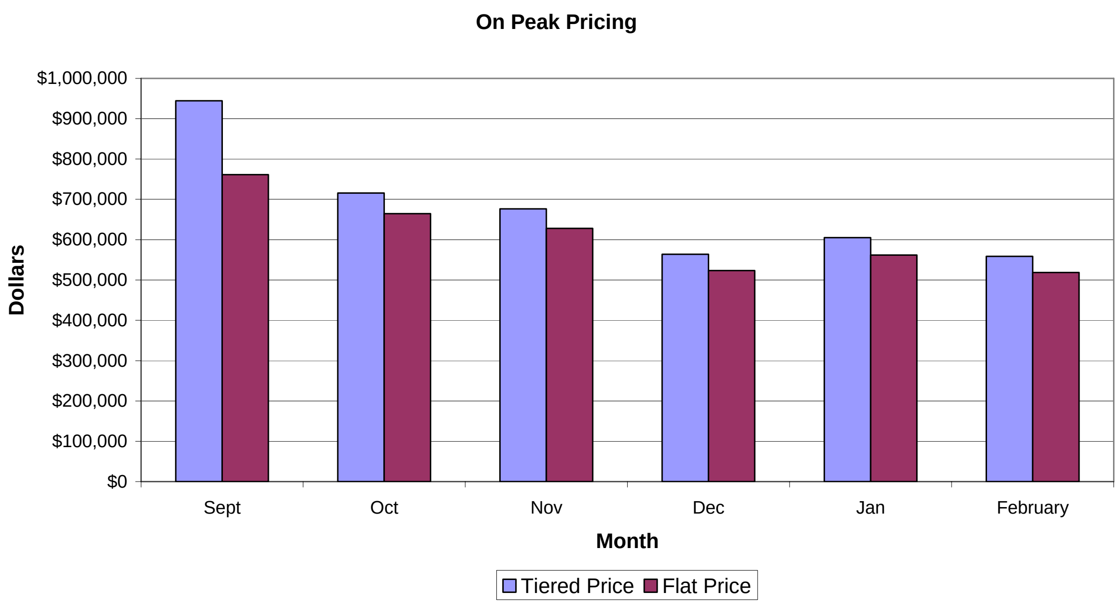

Figure 109. Tiered Price On-Peak vs. Flat Price from September 1, 2005 to February 28, 2006

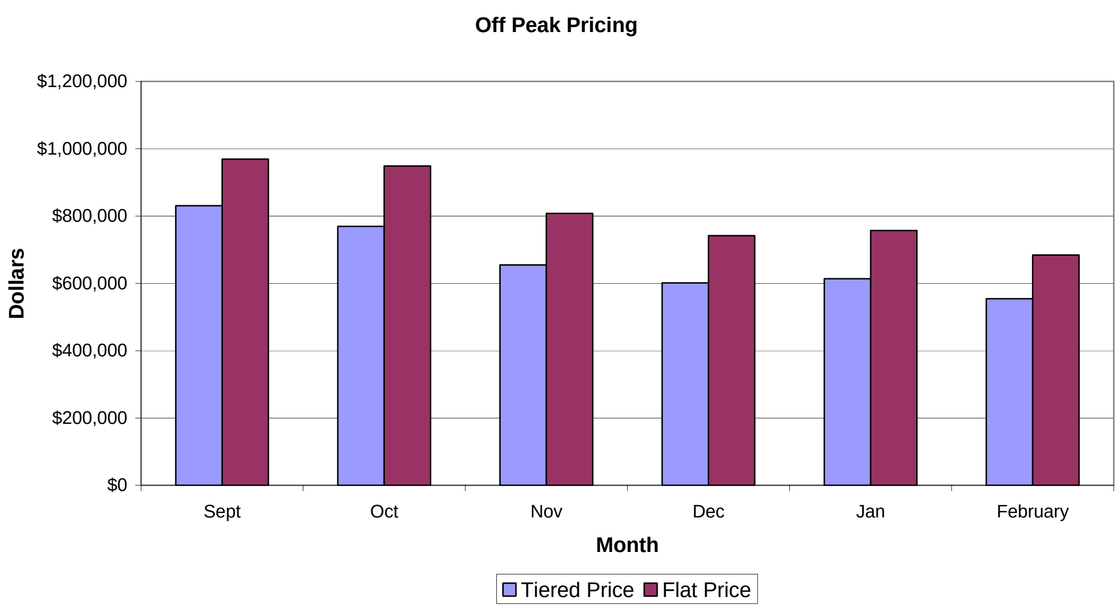

Figure 110. Tiered Price Off-Peak vs. Flat Price from September 1, 2005 to February 28, 2006

In general, if the on-peak time was changed to 6 am to 6 pm, 40% of energy would be used on-peak time and 60% percent of energy would be consumed off-peak time, giving an additional $100,000 savings for a period of six months compared to the savings obtained with a peak time from 6 am to 7 pm. This would result in a total savings of $580,000, around 6.75% lower than the costs on the fixed price.

4.1. Texas A&M at Corpus Christi on the Tiered Price

A good example of possible savings using the tiered price is Texas A&M University in Corpus Christi. They have been on a tiered price structure because of their thermal storage system since deregulation began. From February 1 to August 14, 2005, Corpus Christi purchased electricity on a tiered price (The on-peak hours were from 6 am to 10 pm and off-peak hours were from 10 pm to 6 am). Under this price structure, Corpus Christi paid $746,391 from February 1 to August 15, 2005, saving around 2%, or $11,897 compared to the fixed price. From August 15, 2005 to February 28, 2006, Corpus Christi remained on the tiered price; however the on-peak time was changed to 6 am to 7 pm and off-peak time from 7 pm to 6 am. By reducing the on-peak hours, Corpus paid $1,258,991, 5% lower, or $63,744 less, than purchasing electricity on the fixed price. Corpus Christi could achieve greater savings if the discharge and charge schedule of the thermal storage were optimized. Most of the energy was consumed from 6 am to 10 pm and the peak demand occurred during peak time, which could be avoided to obtain greater energy cost savings on the tiered price.

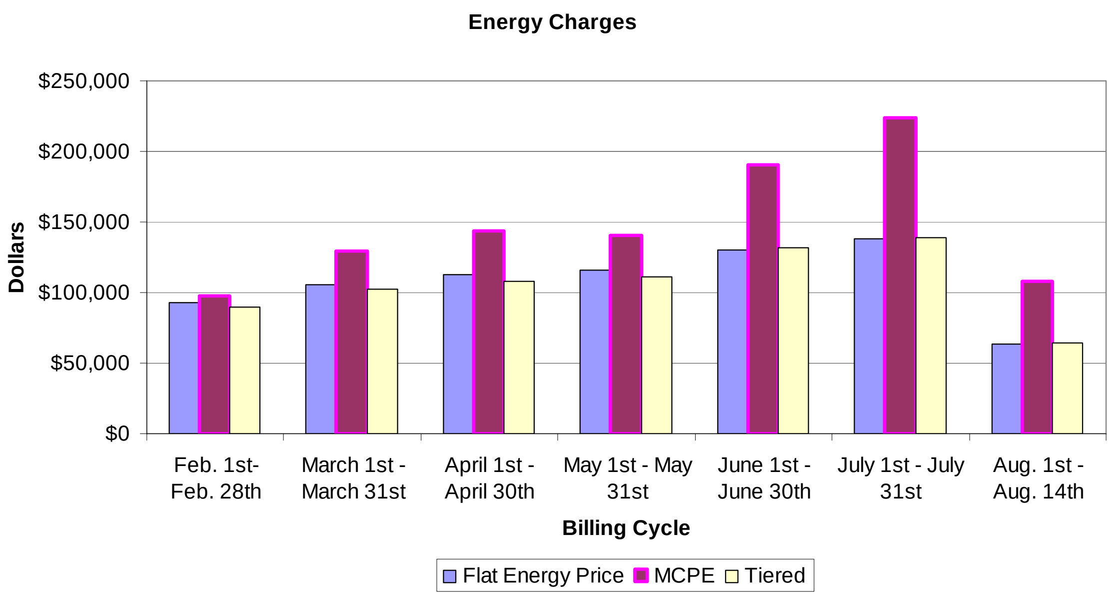

Figure 111. Corpus Christi Energy Prices from February 1 to August 14, 2005

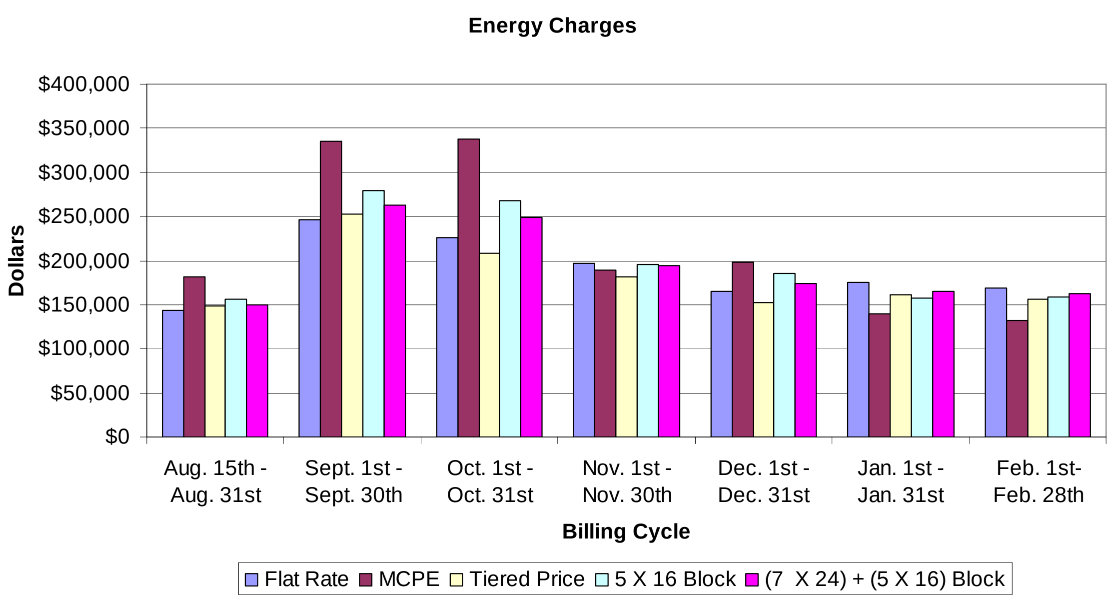

Figure 112. Corpus Christi Energy Prices from August 15, 2005 to Feb. 28, 2006

B. Results for Purchasing Electricity Excluding Texas A&M University in Corpus Christi

Considering the fact that it will be most advantageous for Corpus Christi to stay on the tiered price, the different scenarios of purchasing electricity for all facilities excluding Corpus were analyzed.

1. Purchasing Electricity on the Tiered Price for Corpus and on the Spot Market for the Other IDR Facilities

Purchasing electricity on the tiered price for Corpus Christi, around 12% of the load of all IDR accounts, and on the spot market for all the facilities, had higher energy costs compared to purchasing electricity on the fixed price for all facilities and on the tiered price for Corpus. If the electricity would have been purchased on the tiered price for Corpus and on the spot market for all the other facilities from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006, the costs would have had increased, respectively, by $2,805,000 and $1,100,000, around 49% and 13% higher, when compared to purchasing electricity on the tiered price for Corpus and on the fixed price for all the other facilities. See Figure 103.

Purchasing electricity on the tiered price for Corpus Christi and on the spot market for the other IDR accounts compared to purchasing electricity for all IDR accounts on the tiered price was $2,851,000 (49%) and $1,510,000 (18%) higher, respectively, from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006, as noted in Figure 114.

2. Purchasing Electricity on the Tiered Price for Corpus and on the First Block Structure (7 X 24 + 5 X 16) for the Other IDR Facilities

At the same time, purchasing electricity for Corpus Christi on the tiered price and for all the other IDR accounts on the first block structure (7 X 24 plus 5 X 16) would have cost $8,754,205. It could only decrease about $56,000, about 1% lower, compared to purchasing electricity on the block structure for all facilities, and about 3% higher than purchasing electricity on the tiered price for Corpus Christi and on the fixed price for all the other universities, and 8% higher than purchasing electricity on the tiered price for all facilities. It was around 9% lower than purchasing electricity on the tiered price for Corpus Christi and on the spot market for all other facilities. See Figure 114.

3. Purchasing Electricity on the Tiered Price for Corpus and on the Fixed Energy Rate for the Other IDR Facilities

Purchasing electricity on the tiered price for Corpus Christi and on the fixed rate for all the other facilities would have cost $5,768,219 and $8,498,651, respectively, from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006. These two values are 1% and 5% higher, respectively, than purchasing electricity for all facilities under the tiered price from March 1 to August 31, 2005 and from September 1, 2005 to February 28, 2006. See Figure 114.

4. Purchasing Electricity on the Tiered Price for Corpus and on the Second Block Structure (5 X 16) for the Other IDR Facilities

If the second block structure (5 X 16) was considered without Corpus Christi, this method would still be high compared to other methods, having a cost of $9,040,115, only decreasing costs by approximately $75,000, about 1% lower compared to purchasing electricity on the block structure for all facilities. It would be around 6% higher than purchasing electricity on the tiered price for Corpus Christi and on the fixed price for all the other universities, and 11 % higher than purchasing electricity on the tiered price for all facilities. It was around 6% lower than purchasing electricity on the tiered price for Corpus Christi and on the spot market for all other facilities. See Figure 113 and Figure 114 for energy costs under different scenarios while having Corpus Christi on the tiered price.

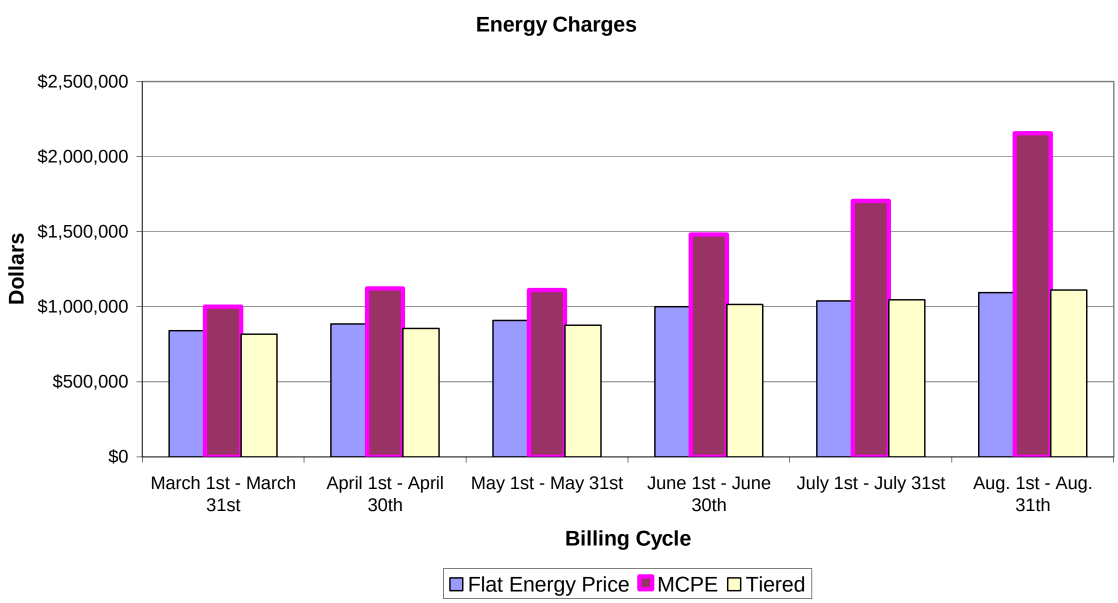

Figure 113. Price Analysis Results Excluding Corpus Christi From March 1 to August 31, 2005

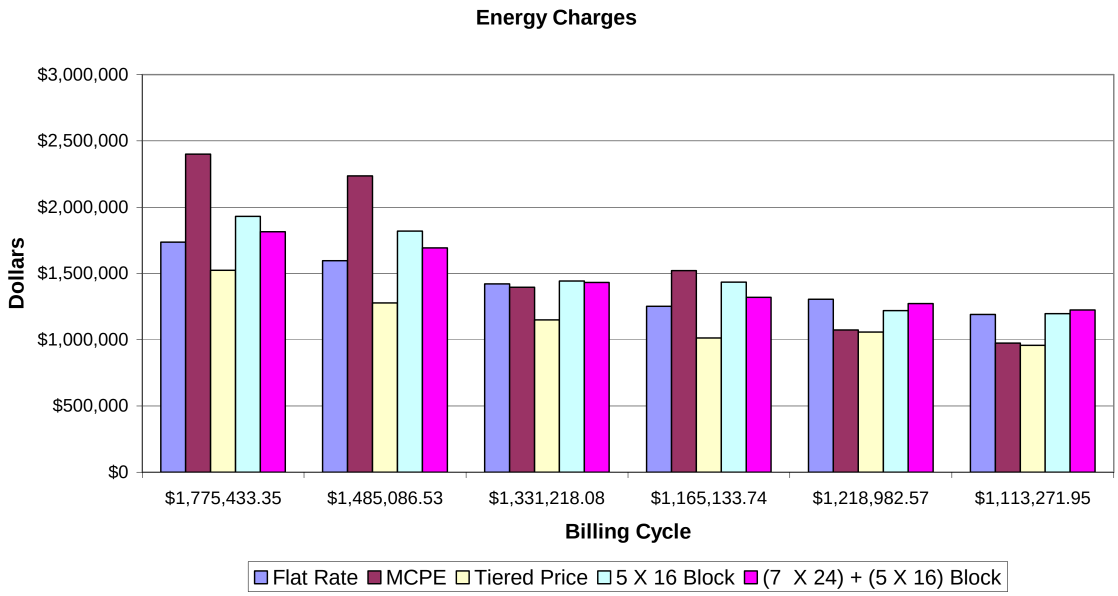

Figure 114. Price Analysis Results Excluding Corpus Christi from Sept. 1, 2005 to Feb. 28, 2006

C. Day-Ahead Market

Purchasing electricity on the day-ahead market would have been lower than purchasing electricity on the spot market; however it would still have been more expensive than purchasing electricity than the other methods. In the spring of 2005, there were 45 new monthly accounts added to the TAMUS contract, and they were placed on the day-ahead market for electricity purchases. Their load was too much to add to the existing contract at the lower prices. These facilities were purchasing electricity on the day-ahead market from May to August 15 2005. The total load consumption from May to August was 1,775,530 kWh resulting in $133,144 ($0.075 per kWh) in energy charges. If they could have been under the energy charge of the contract for the smaller accounts, their energy charge would have been $81,000, saving almost 40% in energy charges. However, all these accounts were on the local utility's "price-to-beat" rates, averaging more than 8 cents per kWh. Therefore, they saved a significant amount of money by going onto the day-ahead rate instead of staying on the "price-to-beat". Two facilities at TEEX were able to be placed on the old contract, and these two accounts saved thousands of dollars in just four months. Their electricity bills dropped about 25%, compared to the "price-to-beat" rates they were paying.

CHAPTER X

CONCLUSIONS AND RECOMMENDATIONS

A. Summary Conclusions

The open competitive electricity market in Texas gives the different Universities involved in this research the opportunity to save money when purchasing electricity. The results on this thesis are based on 9 IDR accounts.

This analysis showed that it is beneficial for all accounts to purchase electricity on the tiered price. In just a period of 6 months (September 2005 thru February 2006) with a peak schedule from 6 am to 7 pm and an off-peak schedule from 7 pm to 6 am, purchasing electricity on the tiered price would be $480,000 dollars less than the fixed rate, $1,730,800 dollars less than the spot market, $721,000 dollars less than the first block structure and $1,026,000 less than the 5 X 16 block structure. If electricity were to be purchased on the tiered price in a period of 12 months (from March 2005 to February 2006) instead of the fixed rate, around $550,000 dollars could be saved, approximately 4.2% lower than the costs on the fixed rate. If the peak schedule were changed to 6 am to 6 pm, the savings for twelve months could be around $800,000 dollars, about 5.6% lower than the costs on the fixed rate.

Purchasing electricity on the tiered price from March 1, 2005 to February 28, 2006 would have been the most economical method for all the IDR accounts together; however, the tiered price would have been most economical for each IDR account as well. By purchasing electricity on the tiered price for six months prior to signing the new contract Galveston would have paid $273,375, around $3,655 lower than purchasing electricity on the fixed cost. Kingsville would have paid $824,481, around $8,363 lower than under the fixed price. Laredo would have paid $467,501, around $3,516 lower than under the fixed cost. Commerce 7 would have paid $589,531, around $3,057 lower than under the fixed cost. Commerce 8 would have paid $134,092, around $2,017 less than under the fixed cost. Tarleton would have paid $692,682, around $6,676 less than under the fixed cost. IBT would have paid $174,130, around $2,048 lower than under the fixed cost. SFA would have paid $1,817,616, around $23,564 lower than under the fixed cost.

By purchasing electricity on the tiered price for six months after signing the new contract Galveston would have paid $292,875, around $17,845 lower than purchasing electricity on the fixed rate. Kingsville would have paid $1,145,110, around $69,038 lower than under the fixed price. Laredo would have paid $627,254, around $36,204 lower than under the fixed cost. Commerce 7 would have paid $827,621, around $34,082 lower than under the fixed cost. Commerce 8 would have paid $178,659, around $12,836 less than under the fixed cost. Tarleton would have paid $1,026,406, around $60,593 less than under the fixed cost. IBT would have paid $255,325, around $15,767 lower than under the fixed cost. SFA would have paid $2,625,180, around $163,000 lower than under the fixed cost. From the research in this thesis, it was seen that Corpus Christi is not fully taking advantage of the thermal storage system. If the thermal Storage charge and discharge process are optimized, the energy, transmission and distribution costs for Corpus Christi would decrease.

Purchasing electricity on the MCPE price IS HIGH RISK even though it has been low for the first two months of 2006. In 2005, it was seen that the MCPE price, although it could decrease by as much as 24%, could also increase its value by 100% or more. Therefore, even though the MCPE price has been low for the first three months of 2006, it could increase its value significantly in the summer, thus increasing the total cost of energy for the whole year, and removing any savings that could have been achieved at the beginning of 2006. According to Dr. William Gray from the University of Colorado, the hurricane season of 2006 is predicted to have 9 hurricanes from which 5 are predicted to be categories 3 to 5. The probability of one major hurricane hitting the Gulf coast of the US affecting natural gas production is 47%. It also forecasted 17 named storms during the hurricane season. Dr. Gray had predicted 6 hurricanes for 2005, with 3 being major hurricanes and around 11 storms. In reality in 2005, there were 26 named storms, and 14 hurricanes from which 2 (Katrina and Rita) brought significant consequences to the oil and natural gas production of the US.

If it is desirable to risk purchasing electricity on the spot market, the first block structure (7 X 24 plus 5 X 16) would be preferable over the second block structure (5 X 16). The first block structure was $304,000 (3.4%) and $704,000 (8%) lower than the second block structure and the spot market, respectively. The first structure would purchase approximately 20% of the total energy on the spot market compared to 40% on the second block structure and 100% on the spot market.

The results of this analysis were based on the weather and political conditions of 2005. Therefore, different climate and weather scenarios may bring different results. However, due to the predicted Hurricane season of 2006 and the international price instability, the results obtained should not be too far from the results under the scenarios for 2006 and 2007.

Finally, the fixed price structure has saved the TAMUS millions of dollars in electricity costs over the past four years. For the fiscal year 2007 (and perhaps the fiscal year 2008) purchases, either the tiered or fixed price should be favored because there is less risk over the MCPE.

B. Recommendations

The TAMUS should continue to aggregate its electrical loads and purchase electricity under one contract. It avoids having multiple RFPs (up to 12 separate RFPs) and provides a uniform purchasing strategy. The market should be watched closely to determine whether it is best to procure short-term or long-term contracts. If significant savings could be achieved with a long-term (2 or 3 year contract), then that should be considered. Similarly, recommendations to purchase on the MCPE, flat rate, tiered, or block structures may vary from year to year, based on market conditions. In the near-term natural gas and electricity market, a tiered pricing scenario appears to be the most favorable, particularly if the ERCOT on-peak time can be shifted from 6 am to 6 pm for the duration of the contract.

The loads of the universities need to be monitored for changes in usage patterns and potential changes in the number of meters. If Stephen F. Austin University were to drop out from the aggregation, for example, that would be a major change on the amount of energy purchased and the distribution of usage. If Kingsville converts to scalar meters from their IDR meter, that will dramatically impact the IDR and scalar loads.

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APPENDIX A

Total Price for Energy for each University Six Months Prior to September 1st, 2006

Table 23. Galveston Price Results from March 1 to August 31, 2005

Galveston				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$38,361.57	$47,554.46	$36,979.21	840,893.75
April 1 - April 30	$42,829.76	$55,401.87	$41,046.22	938,837.25
May 1 - May 31	$43,336.00	$54,006.75	$41,464.11	949,934.25
June 1 - June 30	$40,586.10	$65,432.48	$41,103.19	889,655.75
July 1 – July 31	$56,051.28	$94,543.66	$56,169.37	1,228,655.75
Aug. 1 - Aug. 31	$55,866.82	$121,026.93	$56,613.67	1,224,612.50
TOTAL	$277,031.52	$437,966.14	$273,375.77	6,072,589.25
$/kWh	$0.0456	$0.0721	$0.0450	

Table 24. Corpus Christi Price Results from March 1 to August 31, 2005

Corpus Christi				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$105,504.57	$129,748.28	$102,293.31	2,312,682.48
April 1 - April 30	$112,402.22	$143,466.07	$107,964.23	2,463,880.32
May 1 - May 31	$116,143.06	$140,112.60	$111,308.80	2,545,880.40
June 1 - June 30	$130,190.85	$190,370.08	$131,933.13	2,853,810.72
July 1 – July 31	$137,825.66	$224,138.83	$138,842.99	3,021,167.52
Aug. 1 - Aug. 31	$152,688.32	$288,852.64	$155,679.77	3,346,960.08
TOTAL	$754,754.68	$1,116,688.50	$748,022.22	16,544,381.52
$/kWh	$0.0456	$0.0675	$0.0452	

Table 25. Kingsville Price Results from March 1 to August 31, 2005

Kingsville				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$127,170.96	$154,511.77	$122,671.15	2,787,614.16
April 1 - April 30	$127,801.85	$162,767.54	$122,933.77	2,801,443.44
May 1 - May 31	$129,825.26	$158,248.85	$124,850.55	2,845,797.12
June 1 - June 30	$142,869.61	$210,353.01	$145,190.37	3,131,731.92
July 1 – July 31	$150,361.04	$245,517.85	$151,428.98	3,295,945.68
Aug. 1 - Aug. 31	$154,816.75	$291,411.47	$157,406.84	3,393,615.84
TOTAL	$832,845.48	$1,222,810.49	$824,481.66	18,256,148.16
$/kWh	$0.0456	$0.0670	$0.0452	

Table 26. Laredo Price Results from March 1 to August 31, 2005

Laredo				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$62,542.48	$76,487.38	$60,609.39	1,370,944.32
April 1 - April 30	$70,276.84	$90,123.13	$67,723.31	1,540,483.20
May 1 - May 31	$77,486.19	$94,878.79	$74,405.80	1,698,513.60
June 1 - June 30	$84,178.97	$124,528.11	$85,777.20	1,845,220.80
July 1 – July 31	$85,558.13	$140,775.85	$86,327.58	1,875,452.16
Aug. 1 - Aug. 31	$90,974.89	$171,370.65	$92,657.85	1,994,188.80
TOTAL	$471,017.51	$698,163.91	$467,501.14	10,324,802.88
$/kWh	$0.0456	$0.0676	$0.0453	

Table 27. Commerce-7 Price Results from March 1 to August 31, 2005

Commerce 7				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$79,967.37	$97,736.64	$78,245.46	1,752,901.56
April 1 - April 30	$85,292.53	$113,209.82	$83,133.45	1,869,630.12
May 1 - May 31	$93,717.58	$122,642.91	$91,100.94	2,054,309.04
June 1 - June 30	$108,084.45	$173,358.22	$111,444.44	2,369,233.80
July 1 – July 31	$105,414.13	$194,082.17	$107,727.29	2,310,699.96
Aug. 1 - Aug. 31	$113,998.23	$260,104.30	$117,880.20	2,498,865.12
TOTAL	$586,474.28	$961,134.06	$589,531.78	12,855,639.60
$/kWh	$0.0456	$0.0748	$0.0459	

Table 28. Commerce-8 Price Results from March 1 to August 31, 2005

	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$16,619.92	$20,066.48	$15,931.93	364,312.08
April 1 - April 30	$17,954.26	$23,401.17	$17,113.78	393,561.18
May 1 - May 31	$21,164.32	$26,954.41	$20,189.49	463,926.42
June 1 - June 30	$25,832.94	$40,417.65	$26,093.05	566,263.44
July 1 – July 31	$27,197.56	$48,043.65	$27,191.32	596,176.20
Aug. 1 - Aug. 31	$27,340.73	$59,848.87	$27,572.94	599,314.46
TOTAL	$136,109.72	$218,732.23	$134,092.51	2,983,553.78
$/kWh	$0.0456	$0.0733	$0.0449	

Table 29. Tarleton Price Results from March 1 to August 31, 2005

Tarleton				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$103,712.84	$125,419.18	$100,341.40	2,273,407.20
April 1 - April 30	$107,036.56	$141,283.50	$102,917.83	2,346,264.00
May 1 - May 31	$102,989.16	$130,562.52	$98,860.07	2,257,544.16
June 1 - June 30	$122,315.85	$193,531.56	$124,326.17	2,681,189.28
July 1 – July 31	$128,309.07	$229,618.17	$129,165.63	2,812,561.92
Aug. 1 - Aug. 31	$134,995.49	$301,217.92	$137,071.09	2,959,129.44
TOTAL	$699,358.98	$1,121,632.85	$692,682.18	15,330,096.00
$/kWh	$0.0456	$0.0732	$0.0452	

Table 30. IBT Price Results from March 1 to August 31, 2005

IBT				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$29,226.68	$35,987.16	$28,196.90	640,655.00
April 1 - April 30	$28,081.31	$36,180.71	$26,946.79	615,548.25
May 1 - May 31	$29,208.72	$36,457.19	$28,061.30	640,261.25
June 1 - June 30	$29,516.62	$47,923.79	$29,999.36	647,010.50
July 1 – July 31	$29,971.98	$51,647.26	$30,205.96	656,992.00
Aug. 1 - Aug. 31	$30,173.34	$65,626.52	$30,720.05	661,406.00
TOTAL	$176,178.65	$273,822.63	$174,130.37	3,861,873.00
$/kWh	$0.0456	$0.0709	$0.0451	

Table 31. SFA Price Results from March 1 to August 31, 2005

SFA				
	Flat Rate	**MCPE**	**Tiered Price**	**kWh**
March 1 - March 31	$281,383.55	$339,880.86	$271,449.20	6,167,986.56
April 1 - April 30	$297,924.73	$391,008.09	$285,516.80	6,530,572.80
May 1 - May 31	$299,775.82	$375,270.11	$287,412.96	6,571,149.12
June 1 - June 30	$314,847.46	$493,571.66	$319,305.87	6,901,522.56
July 1 – July 31	$317,334.59	$561,951.82	$318,802.82	6,956,040.96
Aug. 1 - Aug. 31	$329,914.76	$729,302.36	$335,129.15	7,231,800.96
TOTAL	$1,841,180.91	$2,890,984.90	$1,817,616.81	40,359,072.96
$/kWh	$0.0456	$0.0716	$0.0450	

APPENDIX B

Total Price for Energy for each University Six Months after August 31st, 2005

Table 32. Galveston Price Results from September 1, 2005 to February 28, 2006

Galveston								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$72,002.18	$76,020.44	$66,204.51	$94,147.69	$67,648.51	$69,390.22	$74,198.89	897,688.25
Oct. 1 - Oct. 31	$73,106.92	$78,782.93	$64,947.70	$104,772.96	$59,617.63	$70,519.39	$77,220.81	880,646.75
Nov. 1 - Nov. 30	$55,980.56	$56,294.63	$56,052.82	$55,438.00	$51,794.41	$56,694.41	$57,060.13	760,038.25
Dec. 1 - Dec. 31	$44,335.26	$48,484.22	$41,645.22	$52,644.94	$38,222.15	$43,924.31	$48,357.23	564,681.00
Jan. 1 - Jan. 31	$43,408.26	$41,610.42	$46,162.45	$36,826.21	$42,584.06	$44,797.57	$42,438.53	625,931.50
Feb. 1- Feb. 28	$33,748.10	33,281.93	$35,708.72	$28,987.00	$33,008.80	$35,497.09	$34,803.64	484,186.00
TOTAL	$322,581.29	$334,474.57	$310,721.42	$372,816.80	$292,875.56	$320,822.99	$334,079.22	4,213,171.75
$/kWh	$0.0766	$0.0794	$0.0738	$0.0885	$0.0695	$0.0761	$0.0793	

Table 33. Corpus Christi Price Results from September 1, 2005 to February 28, 2006

Corpus Christi						
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**kWh**
Sept. 1- Sept. 30	$263,403.68	$279,146.84	$246,971.07	$334,967.76	$252,454.17	3,348,760.32
Oct. 1 - Oct. 31	$248,516.20	$267,415.21	$226,159.13	$338,197.04	$207,797.89	3,066,564.48
Nov. 1 - Nov. 30	$194,125.10	$195,580.16	$196,287.62	$189,661.88	$181,572.64	2,661,527.04
Dec. 1 - Dec. 31	$173,664.88	$185,592.48	$164,999.68	$198,124.61	$151,750.98	2,237,283.84
Jan. 1 - Jan. 31	$164,857.57	$157,434.62	$175,348.45	$139,070.23	$161,281.62	2,377,606.08
Feb. 1- Feb. 28	$162,030.37	$158,720.98	$168,891.56	$132,242.45	$155,833.77	2,290,055.04
TOTAL	$1,206,597.79	$1,243,890.28	$1,178,657.51	$1,332,263.97	$1,110,691.07	15,981,796.80
$/kWh	$0.0755	$0.0778	$0.0738	$0.0834	$0.0695	

Table 34. Kingsville Price Results from September 1, 2005 to February 28, 2006

Kingsville								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$267,162.41	$282,723.33	$250,667.40	$338,349.38	$257,291.19	$260,021.94	$278,631.18	3,398,880.00
Oct. 1 - Oct. 31	$263,748.33	$283,215.02	$240,157.07	$357,501.47	$220,944.15	$257,791.41	$280,760.46	3,256,367.04
Nov. 1 - Nov. 30	$205,702.54	$206,367.95	$207,550.98	$199,633.26	$192,499.31	$208,999.51	$209,796.35	2,814,250.56
Dec. 1 - Dec. 31	$200,960.45	$212,805.67	$191,866.23	$222,337.10	$175,754.06	$203,501.67	$214,973.23	2,601,576.00
Jan. 1 - Jan. 31	$192,779.79	$184,030.65	$204,938.03	$161,755.78	$188,953.50	$199,446.45	$187,996.29	2,778,820.80
Feb. 1- Feb. 28	$111,689.98	$108,519.57	$118,969.56	$92,362.23	$109,668.44	$117,018.03	$113,198.53	1,613,146.56
TOTAL	$1,242,043.50	$1,277,662.20	$1,214,149.27	$1,371,939.23	$1,145,110.66	$1,246,779.01	$1,285,356.04	16,463,040.96
$/kWh	$0.0754	$0.0776	$0.0738	$0.0833	$0.0696	$0.0757	$0.0781	

Table 35. Laredo Price Results from September 1, 2005 to February 28, 2006

Laredo								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$149,623.45	$158,532.14	$140,362.06	$190,353.83	$144,108.16	$145,717.74	$156,351.58	1,903,214.40
Oct. 1 - Oct. 31	$141,606.39	$152,208.04	$128,735.29	$192,944.41	$118,428.99	$138,345.21	$150,844.46	1,745,563.20
Nov. 1 - Nov. 30	$109,133.68	$110,168.53	$109,963.30	$107,098.35	$101,896.91	$110,677.70	$111,881.51	1,491,027.84
Dec. 1 - Dec. 31	$97,897.85	$103,997.87	$93,599.23	$109,089.26	$86,218.69	$98,896.90	$104,968.87	1,269,142.08
Jan. 1 - Jan. 31	$91,790.34	$88,355.84	$97,594.97	$77,386.92	$90,190.96	$94,951.07	$90,327.94	1,323,321.60
Feb. 1- Feb. 28	$89,555.24	88,280.69	$93,204.09	$72,615.55	$86,411.05	$96,844.69	$94,255.65	1,263,784.32
TOTAL	$679,606.95	$701,543.10	$663,458.94	$749,488.32	$627,254.78	$685,433.30	$708,630.01	8,996,053.44
$/kWh	$0.0755	$0.0780	$0.0738	$0.0833	$0.0697	$0.0762	$0.0788	

Table 36. Commerce-7 Price Results from September 1, 2005 to February 28, 2006

Commerce 7								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$200,324.27	$212,333.05	$182,753.66	$268,092.83	$191,132.84	$192,571.02	$206,877.12	2,478,015.72
Oct. 1 - Oct. 31	$178,725.07	$191,143.35	$163,965.50	$238,750.14	$153,150.10	$175,504.29	$190,168.54	2,223,261.00
Nov. 1 - Nov. 30	$140,678.97	$143,522.63	$140,991.01	$140,589.28	$132,706.46	$142,044.31	$145,400.84	1,911,742.56
Dec. 1 - Dec. 31	$135,154.13	$150,795.64	$126,061.90	$164,007.91	$117,360.59	$133,727.85	$150,603.96	1,709,313.84
Jan. 1 - Jan. 31	$119,042.65	$117,303.12	$126,522.67	$102,813.58	$118,984.33	$122,391.86	$119,811.31	1,715,561.64
Feb. 1- Feb. 28	$117,031.70	$117,640.83	$121,409.70	$97,046.35	$114,287.17	$126,429.38	$125,965.31	1,646,233.20
TOTAL	$890,956.79	$932,738.62	$861,704.44	$1,011,300.10	$827,621.49	$892,668.71	$938,827.08	11,684,127.96
$/kWh	$0.0763	$0.0798	$0.0738	$0.0866	$0.0708	$0.0764	$0.0804	

Table 37. Commerce-8 Price Results from September 1, 2005 to February 28, 2006

Commerce 8								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$42,064.25	$44,759.62	$38,181.18	$56,931.98	$38,731.72	$40,343.78	$43,550.42	517,710.96
Oct. 1 - Oct. 31	$42,155.95	$45,138.50	$38,906.64	$55,279.66	$35,412.62	$41,448.25	$44,974.99	527,547.60
Nov. 1 - Nov. 30	$31,583.22	$31,822.40	$31,802.21	$31,213.19	$29,109.86	$31,961.80	$32,240.54	431,216.46
Dec. 1 - Dec. 31	$30,502.18	$34,453.67	$28,233.22	$37,416.39	$25,802.84	$30,166.51	$34,428.16	382,823.28
Jan. 1 - Jan. 31	$24,456.42	$23,314.78	$25,939.54	$20,778.18	$23,677.50	$25,268.37	$23,773.46	351,722.52
Feb. 1- Feb. 28	$27,416.63	$26,643.51	$28,433.62	$22,512.67	$25,925.33	$29,729.64	$28,424.03	385,540.56
TOTAL	$198,178.65	$206,132.48	$191,496.40	$224,132.06	$178,659.86	$198,918.35	$207,391.60	2,596,561.38
$/kWh	$0.0763	$0.0794	$0.0738	$0.0863	$0.0688	$0.0766	$0.0799	

Table 38. Tarleton Price Result from September 1, 2005 to February 28, 2006

Tarleton								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$243,339.1	$258,306.3	$219,656.5	$330,816.5	$225,391.9	$233,362.9	$251,202.3	2,978,393.8
Oct. 1 - Oct. 31	$213,484.5	$228,209.9	$196,269.6	$282,799.7	$180,643.3	$209,745.8	$227,136.5	2,661,282.7
Nov. 1 - Nov. 30	$180,249.5	$181,188.0	$180,985.9	$177,461.8	$167,890.7	$182,784.8	$183,872.6	2,454,046.6
Dec. 1 - Dec. 31	$168,817.4	$186,978.2	$158,173.0	$201,779.1	$145,725.3	$167,933.6	$187,209.5	2,144,718.7
Jan. 1 - Jan. 31	$154,600.3	$148,214.9	$164,387.8	$131,005.6	$151,861.6	$159,648.9	$151,240.5	2,228,987.5
Feb. 1- Feb. 28	$161,386.9	$158,570.1	$167,527.5	$132,998.0	$154,893.9	$174,651.4	$169,135.4	2,271,559.7
TOTAL	$1,121,878	$1,161,467	$1,087,000	$1,256,861	$1,026,407	$1,128,127	$1,169,797	14,738,989
$/kWh	$0.0761	$0.0788	$0.0738	$0.0853	$0.0696	$0.0765	$0.0794	

Table 39. IBT Price Results from September 1, 2005 to February 28, 2006

IBT								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$50,538.20	$53,389.41	$46,023.21	$67,554.65	$47,219.95	$48,641.24	$52,047.79	624,043.50
Oct. 1 - Oct. 31	$53,352.24	$57,299.37	$47,841.33	$75,303.88	$44,043.49	$51,786.09	$56,442.23	648,696.00
Nov. 1 - Nov. 30	$44,472.42	$44,645.64	$44,647.18	$43,520.97	$41,425.50	$45,202.19	$45,397.68	605,385.50
Dec. 1 - Dec. 31	$47,362.17	$51,123.53	$45,039.95	$53,625.22	$41,597.45	$47,839.98	$51,657.31	610,711.25
Jan. 1 - Jan. 31	$43,236.36	$41,416.10	$45,951.06	$36,380.93	$42,499.63	$44,740.92	$42,327.40	623,065.25
Feb. 1- Feb. 28	$40,076.45	39,318.00	$41,590.15	$32,772.59	$38,539.33	$43,391.87	$41,959.37	563,934.25
TOTAL	$279,037.84	$287,192.05	$271,092.89	$309,158.23	$255,325.36	$281,602.29	$289,831.78	3,675,835.75
$/kWh	$0.0759	$0.0781	$0.0738	$0.0841	$0.0695	$0.0766	$0.0788	

Table 40. SFA Price Results from September 1, 2005 to February 28, 2006

SFA								
	(7 X 24) + (5X16) Block	**(5X16) Block**	**Flat Rate**	**MCPE**	**Tiered Price**	**(7 X 24) + (5X16) Block W/O Corpus**	**(5X16) Block W/O Corpus**	**kWh**
Sept. 1- Sept. 30	$594,831.54	$631,461.88	$539,277.65	$801,276.29	$551,454.90	$571,131.15	$614,812.28	7,312,239
Oct. 1 - Oct. 31	$548,439.03	$585,848.46	$506,581.22	$721,002.52	$465,048.36	$540,055.26	$584,248.48	6,868,898
Nov. 1 - Nov. 30	$465,078.27	$468,031.93	$467,513.00	$458,517.51	$432,322.30	$471,365.56	$474,807.27	6,339,159
Dec. 1 - Dec. 31	$443,807.84	$490,106.24	$415,608.39	$527,798.41	$382,701.68	$441,703.43	$491,078.77	5,635,368
Jan. 1 - Jan. 31	$406,570.83	$390,916.00	$432,248.23	$344,563.02	$398,949.33	$419,784.16	$399,143.00	5,860,993
Feb. 1- Feb. 28	$411,414.42	$404,425.71	$427,108.15	$338,797.47	$394,704.14	$445,122.76	$431,422.37	5,791,297
TOTAL	$2,870,141.93	$2,970,790.22	$2,788,336.64	$3,191,955.22	$2,625,180.71	$2,889,162.32	$2,995,512.17	37,807,955
$/kWh	$0.0759	$0.0786	$0.0737	$0.0844	$0.0694	$0.0764	$0.0792	

APPENDIX C

Total Price for Aggregated Loads

Table 41. Price Results for Aggregated Load

All Facilities							
Price structure	**March 1 - March 31**	**April 1- April 30**	**May 1 – May 31**	**June 1 – June 30**	**July 1 – July 31**	**Aug. 1 – Aug. 31**	**Total**
Flat Rate	$844,489.94	$889,600.06	$913,646.13	$998,422.84	$1,038,023.44	$1,090,769.33	$5,774,951.73
MCPE	$1,027,392.20	$1,156,841.89	$1,139,134.13	$1,539,486.57	$1,790,319.26	$2,288,761.66	$8,941,935.71
Tiered Price	$816,717.95	$855,296.18	$877,654.01	$1,015,172.79	$1,045,861.93	$1,110,731.57	$5,721,434.43
Price structure	**Sept. 1 - Sept. 30**	**Oct. 1 – Oct. 31**	**Nov. 1 – Nov. 30**	**Dec. 1 – Dec. 31**	**Jan. 1 – Jan. 31**	**Feb. 1- Feb. 28**	**Total**
(7 X 24) + (5X16) Block	$1,883,289.05	$1,763,134.68	$1,427,004.28	$1,342,502.14	$1,240,742.55	$1,154,349.75	$8,811,022.45
(5X16) Block	$1,996,673.01	$1,889,260.73	$1,437,621.83	$1,464,337.54	$1,192,596.43	$1,135,401.34	$9,115,890.87
Flat Rate	$1,730,097.29	$1,613,563.47	$1,435,794.07	$1,265,226.83	$1,319,093.23	$1,202,843.07	$8,566,617.95
MCPE	$2,482,490.85	$2,366,551.73	$1,403,134.25	$1,566,822.89	$1,050,580.47	$950,334.28	$9,819,914.47
Tiered Price	$1,775,433.35	$1,485,086.53	$1,331,218.08	$1,165,133.74	$1,218,982.57	$1,113,271.95	$8,089,126.21

Table 42. Price Results for Aggregated Load Excluding Corpus Christi

Price structure	March 1 - March 31	April 1- April 30	May 1 – May 31	June 1 – June 30	July 1 – July 31	Aug. 1 – Aug. 31	Total	Total With Corpus (tiered Price)
Flat Rate	$738,985.4	$777,197.8	$797,503.1	$868,232.0	$900,197.8	$938,081.0	$5,020,197.0	$5,768,219.3
MCPE	$897,643.9	$1,013,375.8	$999,021.5	$1,349,116.5	$1,566,180.4	$1,999,909.0	$7,825,247.2	$8,573,269.4
Tiered Price	$714,424.6	$747,332.0	$766,345.2	$883,239.7	$907,019.0	$955,051.8	$4,973,412.2	$5,721,434.4
Price structure	**Sept. 1 - Sept. 30**	**Oct. 1 – Oct. 31**	**Nov. 1 – Nov. 30**	**Dec. 1 – Dec. 31**	**Jan. 1 – Jan. 31**	**Feb. 1- Feb. 28**	**Total**	**Total With Corpus (tiered Price)**
(7 X 24) + (5X16) Block	$1,561,180.0	$1,485,195.7	$1,249,730.3	$1,167,694.2	$1,111,029.3	$1,068,684.8	$7,643,514.3	$8,754,205.3
(5X16) Block	$1,677,671.6	$1,611,796.5	$1,260,457.0	$1,283,277.1	$1,057,058.4	$1,039,164.3	$7,929,424.8	$9,040,115.8
Flat Rate	$1,483,126.2	$1,387,404.3	$1,239,506.5	$1,100,227.2	$1,143,744.8	$1,033,951.5	$7,387,960.4	$8,498,651.5
MCPE	$2,147,523.1	$2,028,354.7	$1,213,472.4	$1,368,698.3	$911,510.2	$818,091.8	$8,487,650.5	$9,598,341.6
Tiered Price	$1,522,979.2	$1,277,288.7	$1,149,645.4	$1,013,382.8	$1,057,701.0	$957,438.2	$6,978,435.1	$8,089,126.2

Table 43. Price Results for Aggregated Load while Corpus Christi is on the Tiered Price

All Facilities Excluding Corpus								
Price structure	**March 1 - March 31**	**April 1- April 30**	**May 1 – May 31**	**June 1 – June 30**	**July 1 – July 31**	**Aug. 1 – Aug. 31**	**Total**	**Total With Corpus (tiered Price)**
Flat Rate + Corpus on Tiered Price	$841,279	$885,162	$908,812	$1,000,165	$1,039,041	$1,093,761	$5,768,219	$5,768,219
MCPE+ Corpus on Tiered Price	$999,937	$1,121,340	$1,110,330	$1,481,050	$1,705,023	$2,155,589	$8,573,269	$8,573,269
Tiered Price for all	$816,718	$855,296	$877,654	$1,015,173	$1,045,862	$1,110,732	$5,721,434	$5,721,434
Price structure	**Sept. 1 - Sept. 30**	**Oct. 1 – Oct. 31**	**Nov. 1 – Nov. 30**	**Dec. 1 – Dec. 31**	**Jan. 1 – Jan. 31**	**Feb. 1- Feb. 28**	**Total**	**Total With Corpus (tiered Price)**
(7 X 24) + (5X16) Block + Corpus on Tiered Price	$1,813,634	$1,692,994	$1,431,303	$1,319,445	$1,272,311	$1,224,519	$8,754,205	$8,754,205
(5X16) Block + Corpus on Tiered Price	$1,930,126	$1,819,594	$1,442,030	$1,435,028	$1,218,340	$1,194,998	$9,040,116	$9,040,116
Flat Rate + Corpus on Tiered Price	$1,735,580	$1,595,202	$1,421,079	$1,251,978	$1,305,026	$1,189,785	$8,498,652	$8,498,652
MCPE+ Corpus on Tiered Price	$2,399,977	$2,236,153	$1,395,045	$1,520,449	$1,072,792	$973,926	$9,598,342	$9,598,342
Tiered Price for all	$1,775,433	$1,485,087	$1,331,218	$1,165,134	$1,218,983	$1,113,272	$8,089,126	$8,089,126

APPENDIX D

Block Structure Prices for Different Sizes under Different MCPE Scenarios

Table 44. Energy Price under Different Scenarios for Changed Block Structure

		7 X 24				5 X 16			
Scenario	**Original Size**	**Increasing 1 MW**	**Increasing 2 MW**	**Decreasing 1 MW**	**Decreasing 2 MW**	**Increasing 1 MW**	**Increasing 2 MW**	**Decreasing 1 MW**	**Decreasing 2 MW**
1	$8,634,894	$8,655,017	$8,692,517	$8,627,197	$8,631,684	$8,634,876	$8,647,524	$8,647,130	$8,665,005
2	$8,599,686	$8,627,037	$8,670,970	$8,584,362	$8,580,965	$8,604,851	$8,622,181	$8,609,642	$8,625,121
3	$8,458,766	$8,502,993	$8,563,549	$8,426,027	$8,404,403	$8,475,898	$8,504,849	$8,457,114	$8,460,603
4	$8,388,349	$8,447,033	$8,520,456	$8,340,357	$8,302,966	$8,415,850	$8,454,163	$8,382,138	$8,380,835
5	$8,692,357	$8,704,496	$8,734,446	$8,693,320	$8,707,257	$8,686,887	$8,694,540	$8,709,720	$8,732,989
6	$8,573,692	$8,601,950	$8,647,409	$8,558,274	$8,555,549	$8,579,921	$8,598,881	$8,582,293	$8,596,571
7	$9,022,359	$8,987,046	$8,971,999	$9,072,372	$9,136,964	$8,982,854	$8,958,218	$9,064,651	$9,113,693
8	$9,233,695	$9,167,050	$9,122,513	$9,316,377	$9,414,963	$9,171,856	$9,126,236	$9,292,155	$9,357,979
9	$8,929,688	$8,909,587	$8,908,522	$8,963,414	$9,010,672	$8,900,819	$8,885,859	$8,964,573	$9,005,825
10	$9,048,353	$9,012,133	$8,995,560	$9,098,460	$9,162,380	$9,007,785	$8,981,518	$9,092,000	$9,142,243
11	$8,811,022	$8,807,041	$8,821,484	$8,828,367	$8,858,965	$8,793,853	$8,790,200	$8,837,146	$8,869,407

VITA

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