The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego

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Abstract

Retail electricity rates in the San Diego Gas & Electric service territory more than doubled over a period of three months during the summer of 2000. Much of this increase was subsequently rescinded through a retroactive rate freeze. We examine the impact of these events on overall consumption levels in San Diego. In August 2000, we find that average electricity consumption decreased by approximately 6%. Much of the reduction occurred in late afternoon and late evening, with close to a 9% at from 4 PM to 7 PM. The results for September 2000 are similar to those for August, even though retail rates had significantly dropped on September 1. Demand rebounds somewhat in later months of the year. The lagged response to price changes in both directions during late 2000 is consistent with a hypothesis that customers were reacting more to the prices reflected in their most recent bills rather than to their currently applicable price. Because of the uncertainty about the duration and the credibility of the rate increase, these results should be viewed as a lower bound on the demand reductions that could be achieved through pricing incentives.

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1 Introduction

One of the oft-cited shortcomings of electricity markets is the lack of direct participation by end-use consumers in those markets. Although sophisticated market mechanisms have been developed for power trading at the wholesale level in many areas, the development of retail pricing structures has lagged. In most restructured electricity markets, the bulk of end-use customers have retained traditional rate structures, which adjust to wholesale price movements very slowly, if at all. Many markets offer more advanced rate structures, such as 'real-time' pricing, as an option, but the impact of these rate structures has been blunted in many areas by rate designs intended to recover the costs of transition to deregulation. Relatively few customers have elected to enroll in these advanced rate structures.

The result of these retail rate policies has been a continuation of the disconnect between market outcomes at the wholesale level and the consumption choices of end-use customers. Since restructuring has resulted in far more volatile wholesale prices, the efficiency implications of this disconnect are much more serious. It has been argued that electricity markets will suffer from chronic difficulties until end-users become more active participants in electricity markets.[1]

Even if all end-users were receiving retail rates that more accurately reflected wholesale prices, it is unclear how responsive customers would be to those rates. Although there have been experiments with real-time and time-of-use pricing, these have largely been restricted to small populations, short durations, and relatively modest price fluctuations.[2] Many time-of-use and real-time pricing programs have also been voluntary, creating the concern that those who choose to enroll do so not because they plan to alter their consumption in response to prices, but because they have relatively flat consumption patterns.[3] Between the summers of 1999 and 2000, however, ratepayers in the service territory of San Diego Gas

[1]See Borenstein (2001).

[2]See, for example Caves and Christensen (1980), which examines a pricing experiment in Wisconsin during 1977.

[3]Caves, Herriges,and Kuester (1989) and Train and Mehrez (1994) examine PG&Es voluntary TOU program. Patrick and Wolak (1997) study the response of voluntary real-time customers in the United Kingdom. Reiss and White (2001) study individual consumer response to increasing-block tariff structures using 1993 California data.

& Electric (SDG&E) were the subjects of an unplanned, natural experiment on the impact of retail rate fluctuations on end-use consumption. During this period, rates for most SDG&E electricity customers were based upon a five-week moving average of wholesale power prices. These wholesale prices increase more than four-fold during this time span, leading to a doubling of residential customer rates. In response to the mounting public pressure over these rate increases, a retail rate freeze was reinstated for some customer classes in August of 2000 and made retroactive to July 1, 2000.

In this paper, we examine the impact of these events on the consumption of electricity by SDG&E customers. Because of the complex way in which rates were implemented and then rescinded during this period, this is as much a study of customer expectations about price as it is an examination of the response to a specific price signal. Fortunately, we have a natural control group, customers of a neighboring utility, the Los Angeles Department of Water & Power (LADWP), whose rates remained constant throughout this period. We examine the consumption behavior of SDG&E customers, who experienced a sharp increase in rates, and LADWP customers, whose prices remained constant, while accounting for additional factors affecting demand such as local temperature and economic activity.

Section 2 discusses the background of the California electricity industry and the retail rate structure in San Diego. Section 3 describes the set up and results of a nonparametric model of demand behavior during various periods. We discuss the overall effect of higher prices as well as look at what times of day consumers reduced demand. Retail prices peaked in August, but were retroactively capped for most customers at 1999 levels on September 1. However, we find a reduction in average consumption of about six percent during both August and September 2000. The results for September indicate that customers may have been responding more to the rate levels implied in their most recent bills rather than imputing current rates from available information. Even though the rate increase was uniform across all hours of the day, the demand effect that we measure was not. For some hours of this period, including some of the afternoon peak hours, we see a decrease of around nine percent.

Section 4 attempts to more explicitly model price response. Supporting our results from section 3, we find an elasticity of demand with respect to lagged prices equal to -0.06. However, the effect of lagged prices on current consumption is stronger than that of current prices. These pricing results must be taken with the caveat that customers who anticipated a retroactive rate cut would have perceived the price increase to be less than that reflected in their bill at that time. In Section 5, we summarize our conclusions.

2 Background

California's electricity industry underwent a significant restructuring in the spring of 1998, but end-use customers did not feel the impact of those changes for nearly two years afterward. Since April of 1998 wholesale prices for electricity serving customers in the territories of California's three major investor owned utilities (IOUs) have been set through a market-based process. This process centered around two new institutions created by the restructuring legislation: the now defunct California Power Exchange (PX), which ran a daily wholesale market for electric energy; and the California Independent System Operator (ISO), which operates the transmission network and runs markets for transmission access, ancillary services, and imbalance (real-time) energy. The control area of the ISO encompasses the entire distribution territories of Pacific Gas & Electric, Southern California Edison and SDG&E.

Although the wholesale markets began trading in April 1998, retail rates to customers in most of California continued to be fixed at the lowest rates in real terms in over twenty years up to June of 2001.[4] This rate freeze was implemented as a mechanism for recovering the sunk costs of assets many believed would become 'stranded' by the transition to market based wholesale pricing. The original transition plan called for rates to be set at ten percent below 1996 levels, which were expected to be well above average wholesale levels, for at most four years. The IOUs were allowed to apply the difference between wholesale prices and the retail energy price of energy implied by this rate freeze to the collection of their stranded costs. If wholesale price levels allowed for all utility stranded costs to be

[4]The statewide average retail rates are reported by the California Energy Commission web site.

recovered before the end of the four year transition period, the energy component of retail rates were to 'drop' to wholesale levels.

The two largest California IOUs, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), both had significant investments in nuclear capacity as well as extensive contractual commitments to independent power producers. These investments, viewed as uneconomic in 1996, meant that both PG&E and SCE were perceived to have far greater stranded costs than the third California IOU, San Diego Gas & Electric (SDG&E). Having made relatively modest commitments to both nuclear and independent power, SDG&E recovered its stranded costs by mid-year 1999. Unlike ratepayers in the rest of California, after July 1, 1999, those in San Diego paid retail rates that more directly reflected the current wholesale price of power.

2.1 Retail Rate Structures in San Diego

Between July of 1999 and August of 2000, the bulk of SDG&E electricity customers were billed at a rate based upon the average wholesale cost of power for the month in which they consumed it. Approximately one-fifth of customers receive their bills in any given week, each reflecting the moving average of the previous five weeks. To the extent that weekly average prices varied, the bills received by each of these sets of customers thereby reflected a different rate. SDG&E offered large customers the option of seeing 'real-time' rates that passed along the hourly wholesale cost of power. However, no customer ever took this option. A greater share of large customers pay 'time-of-use' rates, which vary somewhat by time-of-day but for a given hour do not fluctuate from day to day. There are also rate schedules based upon four to twelve week moving averages of wholesale costs, rather than the basic five week average. There are about 50 different tariff schedules resulting in nearly 600 prices for each week. Most of our discussion of prices focuses on the five-week, load-weighted, non-baseline (second tier), residential weekly price.

Table 1 shows the monthly average retail rate for residential customers in San Diego and the average price in the California Power Exchange (PX), the wholesale market upon which those rates were based. Figure 1 plots these averages on a weekly basis. Retail rates also include charges for transmission and distribution costs, as well as other miscellaneous fees. In June of 1999 these other (non-energy) charges accounted for roughly 60% of residential rates. Since most customers are metered only on a monthly basis, the hourly PX price must be mapped to a weekly average using a standardized load profile for each customer class.[5] In other words, the retail rate reflects the average hourly wholesale power cost, where that average is weighted according to the estimated average hourly consumption for all customers in that rate class.[6]

Table 1: Monthly Residential Rates and PX Prices[7]

Month	Residential Rate	Average PX Price
January 1999	\$0.13	\$0.02
February	\$0.13	\$0.02
March	\$0.13	\$0.02
April	\$0.13	\$0.02
May	\$0.13	\$0.02
June	\$0.13	\$0.02
July	\$0.12	\$0.03
August	\$0.13	\$0.03
September	\$0.12	\$0.03
October	\$0.12	\$0.05
November	\$0.13	\$0.04
December	\$0.12	\$0.03
January 2000	\$0.11	\$0.03
February	\$0.11	\$0.03
March	\$0.11	\$0.03
April	\$0.11	\$0.03
May	\$0.11	\$0.05
June	\$0.139 (\$0.144)	\$0.12
July	\$0.174 (\$0.144)	\$0.11
August	\$0.232 (\$0.144)	\$0.17
September	\$0.296 (\$0.147)	\$0.12
October	\$0.227 (\$0.153)	\$0.10
November	\$0.219 (\$0.153)	\$0.17
December	\$0.225 (\$0.153)	\$0.38

[5]SDG&E has seven main customer classes: agriculture, large commercial and industrial, medium commercial and industrial, residential, schedule A6, schedule AD, and small commercial.

[6]In addition to the energy price in the PX, wholesale power costs for an energy service provider also include the costs of ancillary services as well as fees paid to scheduling coordinators (such as the PX) and the ISO. The hourly load profiles are estimated based on surveys of customers by customer class.

[7]Prices in Cents per kWh. The retroactive capped rates for June, July, and August of 2000 are in parentheses. Source: SDG&E (www.sdge.com).

As can be seen from both Table 1 and Figure 1, residential rates declined modestly with the end of the retail rate freeze in July 1999 and then rose sharply in May of 2000 in response to rapidly increasing wholesale prices. By August of 2000, wholesale energy prices had more than tripled from the end of 1999 and the corresponding residential rates (including non-energy related costs) had roughly doubled. Various cost factors such as higher natural gas prices and environmental compliance contributed to this rise, but several studies have also found the market power of suppliers to be significant throughout this period.[8] The price cap was increased from $250/MWh to $750/MWh in October, 1999. The rate was lowered to $500/MWh on July 1, 2000, and lowered again back to $250/MWh on August 7, 2000.

By late June, there was a tremendous outcry from ratepayers who were for the first time directly exposed to the cost impact of these factors. On July 12, State Senator Steve Peace, a Democrat from San Diego, advised customers to defer payment of at least half their July bills. This was in part due to the fact that a one-time rate rebate stemming from the financing of transition charges was due to be distributed to customers at about this time.[9] Throughout much of July, the California Public Utilities Commission and the California Legislature debated proposals for rate relief for San Diegans. Governor Davis signed Assembly Bill 265 on August 27, 2000. This bill froze rates for small and medium-sized (those under 100 kW) retail customers of SDG&E at 6.5 cents/kWh retroactive to June 1, 2000. This resulted in a credit that showed up on customer bills during November and December. Many customers had no bill for two months because of this refund. As a result of this bill, the difference between wholesale costs and retail rates for these customers has been accumulating in a tracking account since June. The future liability for this revenue shortfall remains uncertain, but it is widely expected that future ratepayers will be expected to cover a significant portion of these costs.[10]

[8]See for example Borenstein, Bushnell and Wolak (2000), Joskow and Kahn (2001) and Puller (2001) as well as various analyses by the Dept. of Market Analysis of the California ISO.

[9]Much of the transition costs of industry restructuring, including an immediate 10% rate reduction beginning in 1998, were financed through a special bond issuance backed by ratepayers. In the case of SDG&E, the bond principal exceeded the final transition costs. Rather than pay down the outstanding debt, this excess principal was distributed amongst ratepayers.

[10]Additionally, in August of 2000 residential and small commercial SDG&E customers started to receive their refund for prepayment of Competition Transition Charge bond. The average residential customer

The widely publicized rate increases, followed by calls for non-payment, a one-time refund, and finally a retroactive rate decrease undoubtedly created a great deal of confusion in the minds of end-use customers over the true price of the electricity they were consuming during the summer of 2000. It is reasonable to assert that for at least two months, customers expected that the price they would pay for electricity would be considerably higher than in the previous year. In the following sections, we analyze the impact such expectations had on end-use consumption in the SDG&E service territory.

3 Estimating Electricity Consumption

Although several news accounts and anecdotal stories told of large-scale reductions in demand in the San Diego area during the summer of 2000, Figure 2 shows that average weekly demand trended upward from 1997 through 2000. Of course there are many confounding factors as to why demand did not decrease from 1999 to 2000. For example, there were lower-than normal temperatures during 1999 while 2000 set records throughout the west, and economic growth continued to be robust throughout this period. By comparison, the dashed line in Figure 2 shows the weekly average demand for the LADWP system and the solid black line shows the same statistic for SCE. The same upward trend in demand is present throughout southern California during this period.

Our goal in this paper is to determine the extent to which the volatility of rates, as well as the uncertainty surrounding those rates, influenced end-use consumption in the San Diego area. Because of the uncertainty about prices at this time, we initially do not attempt to explicitly identify the effect of price on consumption. Instead, we determine the degree to which factors other than price *fail* to describe consumption patterns during this time. In other words, we estimate price response in a nonparametric manner by looking at distinct time periods that have differing price levels, price variability, and consumer expectations.

received about $350. AB 265 overrode the Public Utilities Commission's decision on August 21 to hold SDG&E's monthly residential utility bills to $68 for the first 500 kWh per month.

3.1 A Non-Parametric Model of Electricity Demand in San Diego

We study a period from January 1, 1997 to December 31, 2000. We model San Diego demand (D_{SD}) as a function of economic variables ($ECON_{SD}$), weather variables ($WEATHER_{SD}$), and indicator variables capturing stage emergencies and demand periodicity ($INDICATOR$).[11] We use several economic variables that reflect variation by month and Metropolitan Statistical Area (MSA) in order to capture the size and status of the economy. These include unemployment rate, number of people in the labor force, and current and monthly lag of number of building permits, where all variables are modeled assuming a constant elasticity of demand response.

The weather variables include daily mean, minimum, and maximum temperatures, average wind speed, and average visibility range for four weather stations in the area: Miramar, Brown Field, Gillespie, and Lindberg.[12] The mean temperature variables were modeled with a quadratic function, allowing parameters of temperatures above 65 degrees Fahrenheit to differ from those below this level. The other weather variables were modeled linearly. An additional weather variable estimates hours of sunlight.[13]

The indicators account for stage 1, 2, or 3 emergencies, day of week, and hour of day for each season. The indicators of stage emergencies account for days in which the ISO issued a warning that supply would be restricted relative to demand. Each stage alert is accompanied by increasingly emphatic requests for voluntary reductions in demand. The alerts also activate load reductions from customers on interruptible rates, though to different degrees throughout the state.

Also, demand is assumed to be affected by idiosyncratic time shocks. Some of the shocks are specific to the utility ($\varepsilon_{t,SD}$). However, there were probable economic or other 'non-price' shocks to demand that were common to many areas of California. These common shocks are modeled as η_t. Finally, in this section, we model the price shocks using

[11] Hourly demand data for the utilities studied here are taken from the Federal Energy Regulatory Commission, form 714.

[12] Wind speed lowers the effective temperature. Visibility accounts for cloudy days when more artificial lighting is used.

[13] We model sunlight hours as a sinusoidal function of the days to the nearest winter solstice.

month indicator variables ($PRICE\_MONTHS$). This implies that *any* local shocks to demand will be captured by the $PRICE\_MONTHS$ variables that we are interpreting as a price effect.

We write the demand equation:

$$\begin{aligned} \ln(D_{SD}) &= \alpha_{SD} + \beta_{SD} PRICE\_MONTHS + \delta_{SD} ECON_{SD} \\ &\quad + \gamma_{SD} WEATHER_{SD} + \phi_{SD} INDICATOR + \eta_t + \varepsilon_{t,SD}. \end{aligned} \tag{1}$$

A potential drawback to any such nonparametric approach is that factors other than price that are also not considered in these estimates may have impacted demand during this time. Fortunately, there exist control groups whose rates did not change, but whose regional proximity would imply that its customers would be subject to the same regional non-price shocks, η_t, as those in SDG&E. The primary control group that we utilize in this paper is the retail load of the Los Angles Department of Water and Power (LADWP). As a sensitivity, we also examine the retail demand of Southern California Edison (SCE). These control groups are described in more detail in the following subsection. We feel that these utilities provide adequate control groups for San Diego. However, as these control groups are of greater size than SDG&E, it is more appropriate to model η_t as a common multiplicative shock rather than an additive one. Therefore, by differencing the utility areas' demands, we estimate the following equation:

$$\begin{aligned} \ln(D_{SD}) - \ln(D_{CONTROL}) &= \alpha + \beta PRICE\_MONTHS \\ &\quad + \delta_{SD} ECON_{SD} - \delta_{CONTROL} ECON_{CONTROL} \\ &\quad + \gamma_{SD} WEATHER_{SD} - \gamma_{CONTROL} WEATHER_{CONTROL} \\ &\quad + \phi INDICATOR + \varepsilon, \end{aligned} \tag{2}$$

where the variables are defined as in (1). For example, $D_{CONTROL}$ is demand in the control group. Furthermore, the parameters α, β, and ϕ measure the differences in coefficients for the variables affecting both areas (*e.g.,* β is $\beta_{SD} - \beta_{CONTROL}$). The weather data are from two LADWP weather stations located in Burbank and Los Angeles Airport. When SCE is used as a control group, weather data from Ontario and Santa Ana are also included.

The error structure of ε needs to be modeled appropriately in order to allow for hypothesis testing. Tests of serial correlation (using the Durbin-Watson statistic) and heteroskedasticity (using the Cook and Weisberg test) were significant when estimating (2). We account for this error structure by using the Prais-Winsten method, assuming an AR(1) model, with a White correction of the standard errors.

3.2 Control Groups

LADWP, the largest municipally-owned utility in the United States, provides electric service to residential customers within the city of Los Angeles and to portions of the Owens valley. Like most municipal utilities in California, LADWP successfully resisted participating in the restructuring undertaken by the State's large investor-owned utilities. It is not a member of the California Independent System Operator's system and therefore retains control of its transmission assets and acts as it's own control area operator. Having retained ownership of a surplus of generation capacity, LADWP was able to pay down its over $4 billion by virtue of its position as a net seller into the lucrative California wholesale market during 2000 and 2001. Despite the rapid improvement in its financial position, retail rates in LADWP remained constant throughout the period we examine.

Southern California Edison distributes electricity to the bulk of southern California, excluding the cities of Los Angeles and San Diego. Like SDG&E, SCE divested most of its generation assets and opened its system to a form of retail competition, subject to a transition charge that essentially froze rates at 10% below 1996 levels. Unlike SDG&E, the transition period in SCE had not expired by the summer of 2000. The inability of SCE to adjust rates to levels that reflected its wholesale costs during this time were the primary cause of its subsequent financial difficulties. These financial problems caused SCE to suspend payments to its wholesale suppliers in late 2000 and, along with similar defaults by Pacific Gas & Electric, set the stage for the crisis conditions experienced in the market during the winter of 2000-01.

Table 2 shows the aggregate and percent distribution of energy demand (MWh) among major customer classes for SCE, LADWP and SDG&E, respectively, during 2000.[14] SCE is by far the largest utility and, to the extent the distinction is meaningful in southern California, serves a more suburban population. Demand in LADWP averaged about 25% higher than that in San Diego. Demand from large customers was more skewed towards the industrial category in SDG&E and towards the commercial category in LADWP. SDG&E served a larger proportion of residential customers.

Table 2: Summary of Demand Data

	SCE	SDG&E	LADWP
Demand (million MWh)	73.69	15.12	21.12
Residential Share	35.2%	41.7%	28.9%
Commercial Share	34.5%	40.5%	56.9%
Industrial Share	29.3%	17.3%	11.9%
Other share	0.9%	0.5%	2.1%

Selected weather and economic data for the three utility regions are summarized in table 3. The two smaller utilities serve primarily coastal communities with similar climates while SCE has considerable load further inland.[15] Figure 3 shows the labor force and unemployment data for the San Diego and Los Angeles regions from 1997 through 2000. The San Diego area enjoyed a lower overall unemployment rate and experienced a more rapid percent decline in unemployment and increase in labor force over our sample period.[16]

[14] These data are taken from the Energy Information Administration's form 861.

[15] Weather data are taken from the National Climate Data Center.

[16] Unemployment and labor force data are taken from the Bureau of Labor Statistics. New building permits are taken from the U.S. Census Bureau.

Table 3: Summary of Weather and Economic Data

Variable	Location	Mean	Std. Dev.	Min	Max
Daily Mean Temp.	Brown Field (San Diego)	61.04	7.01	16.30	86.40
	LAX (LADWP & SCE)	62.58	6.01	46.70	84.60
	Ontario (SCE)	64.48	9.42	40.20	92.40
Daily Min Temp.	Brown Field (San Diego)	51.95	8.22	33.10	77.00
	LAX (LADWP & SCE)	56.05	7.39	33.30	75.20
	Ontario (SCE)	52.92	8.74	28.00	78.80
Daily Max Temp.	Brown Field (San Diego)	72.67	8.10	53.60	100.40
	LAX (LADWP & SCE)	70.64	6.87	53.60	96.00
	Ontario (SCE)	79.48	12.04	52.00	109.40
Econ. Variables	Building Permits (SD MSA)	1124	416	575	2410
	Building Permits (LA CMSA)	3904	997	2125	7855
	Labor Force (SD MSA - millions)	1.343	0.048	1.262	1.421
	Labor Force (LA CMSA - millions)	4.641	0.115	4.383	4.850
	Unemployment Rate (SD MSA)	3.46	0.59	2.40	4.90
	Unemployment Rate (LA CMSA)	6.15	0.71	4.70	7.80

3.3 Results

Table 4 (at the end of the paper) shows the regression results of (2), using LADWP as a control group. In any given month from August 1999 to July 2000, consumers did not vary consumption by more than 2% from expectations. In August and September of 2000, however, demand was approximately 6% below levels explained by economic and weather variables. Note that the September result shows a comparable reduction, despite the fact that rates had been substantially reduced on September 1. A Wald test indicates that the coefficients for August and September are not significantly different.

The decline in demand moderated to about 3.5% below levels explained by economic and weather variables in the months from October to December. Wald tests indicate that the demand reduction in these months is significantly less than in September. This latter period is at least one month after the price caps had been reinstated for smaller customers. Given the five week cycle in the billing period, most of these customers would have received bills reflecting the lower rate levels by mid-October. These results are more consistent with a hypothesis that consumers were basing their consumption decisions on the prices reflected in their most recent bills rather than on a rational estimation of their current price.

The largest commercial and industrial customers were not eligible for the rate freeze that was reimposed in September. These customers comprised roughly one-third of energy consumption in the San Diego area. The continued reductions relative to earlier periods in October through December 2000 likely reflect the reductions made by these consumers. Since we do not have access to consumption levels by rate-class at this time, we cannot verify this hypothesis.

Most of the significant economic variables reflect expectations. Assuming that labor force growth is a satisfactory indicator of both population growth and economic activity, we would expect that it would be positively related to electricity demand. We estimate the San Diego elasticity of demand with respect to labor force size to be 0.375. Similarly, increased number of building permits reflect economic growth and greater electricity demand.[17]

As a robustness check, we examine the sensitivity of our main demand response findings to factors such as our choice of economic variables and control group. The first two variations test the importance of the control group by first substituting SCE for LADWP and then using no control group. We then examine whether economic variables greatly affect our results using both LADWP and then SCE as controls. Finally, we remove the weather and hour and day indicators but keep the economic variables using LADWP as a control group. Table 5 summarizes the results of these variations. The results with respect to monthly impacts are robust to the choice (or presence) of a control group and even to weather variables. The results are sensitive to the presence of the economic variables, although less so when SCE is the control group.

3.4 Hourly Effects

In order to examine the demand effects during each epoch in more detail, we allowed the monthly fixed effects to vary by hour. The $PRICE\_MONTHS$ variables were interacted

[17] Some economic variables had unexpected results. The L.A. labor force and the San Diego lag of building permits were negatively correlated with demand. The unemployment rates have the opposite sign than expected but are insignificant.

with hourly dummy variables. The other independent variables remain the same. The results for the hourly epoch variables are shown in Table 6. This analysis reveals that the reduction in demand during August and September was not uniform across hours. Figure 4 plots the hourly coefficients of the percent change in demand for the months of June through September. The largest reductions in demand during August came primarily in the late afternoon hours, reaching around to 9% from 4 PM to 7 PM. The 95 percent confidence interval is shown for the August hourly estimates in Figure 5.

4 Explicit Tests for a Price Impact on Demand

The analyses of the previous section take an event study approach to determine whether demand in San Diego behaved differently relative to a control group during the summer of 2000. The results indicate that demand in August and September was in fact lower than would have been expected after accounting for various non-price factors. In this section we test for the significance of the impact of retail prices on this demand behavior. We employ the same regression approach as in section 4, but replace monthly fixed effects with different measures of retail price as an independent variable.

Although the presence of a price effect would be informative, there are many caveats that must be applied to interpreting the results of this kind of analysis. First, a *single* price for all customers in SDG&E does not exist. There are many different customers on different rate schedules. However, only the aggregate SDG&E demand is available. There are no reliable measures of demand by rate class on an hourly basis. We know that the rates of each customer class moved with the wholesale PX price, but the strength of these linkages varied by customer class. Even within the residential rate class, which accounts for roughly a third of demand, the price paid by individual customers varied. Only one-fifth of these customers are billed in a given week. Bills typically arrive five to ten days after the cycle ends. Thus, the price level of each week's group of residential customers differed according to the weekly changes in the 5-week moving average of PX prices and other charges upon which those rates were based. Customers should respond to prices throughout the previous five weeks since they are billed based on an average of all those prices, not only on the current price.

A second important caveat is the fact that there was much contradictory information about retail prices being provided to customers during this time period. Although prices continued to rise throughout the summer of 2000 in San Diego, customers were also being advised not to pay some or all of their bills. Finally, these rates were retroactively adjusted to levels different than those indicated by the movement of the five week weighted average PX price. To the extent that customers anticipated this retroactive rate decrease, they would have responded less aggressively to the price increases as they were happening. There is no way to credibly measure the extent to which these expectations were affecting customer behavior.

Finally, it is important to realize that results from this study will likely understate the price response that could be expected from exposing customers to higher prices over a longer period of time. The long-term price elasticity will be greater than a short-term one. For example, customers can change consumption behavior by investing in more energy efficient technology. In addition, changing behavior can take time. It may take longer exposure to higher prices to "convince" people to turn off lights in rooms not being used or to lower the thermostat when not home. For these reasons, the price response we model should be considered a lower bound of an elasticity measure.

For the explicit test of a price impact, we focus on using LADWP as a control group. We utilize the following regression equation:

$$\begin{aligned} \ln(D_{SD}) - \ln(D_{LA}) &= \alpha + \beta \ln(PRICE) + \delta_{SD} ECON_{SD} - \delta_{LA} ECON_{LA} \\ &\quad + \gamma_{SD} WEATHER_{SD} - \gamma_{LA} WEATHER_{LA} + \phi INDICATOR + \varepsilon. \end{aligned} \tag{3}$$

Due to the complexity of the interaction between aggregate price and aggregate consumer behavior, we test four different models of prices ($PRICE$). The first is a backward-looking model based upon a five week moving average of residential retail prices ending with the week prior to the date of the observation. The second measure utilizes a five-week average of this price centered upon the week of the observation. This is more consistent with a rational expectations model of demand in which customers would have to base current consumption upon estimates of recent, current and near-future prices. A third model simply uses the previous week's retail price. Last, we utilize the current week's retail price. As San Diego represents a relatively small share of the southern California market, we assume that prices are exogenous.

4.1 Results

Table 7 summarizes these results using various models of the retail price. In general, the historic retail prices produce stronger effects than do current or near-future ones. The model using a backward-looking five week moving average produces the strongest price effect, with a nearly 6% reduction implied by a doubling of price. This is consistent with the results of the previous section, as this historic moving average peaked in the first week of September at a level roughly double that of early 2000.

Although it is tempting to treat these results as estimates of the price-elasticity of demand, the caveats given above warn against such a strict interpretation. Although we observe a reduction in demand of around 6% during two months of the summer of 2000, it is nearly impossible to estimate what price customers *thought* they were going to pay at that time.

5 Conclusions

We have attempted to reconstruct the pattern of electricity consumer behavior in San Diego during the volatile summer of 2000. During that summer, retail customers of San Diego Gas & Electric saw their rates rise precipitously, and then had much of that rate increase rescinded through a rate freeze that was applied retroactively to the beginning of June. During this time there was an unprecedented amount of media coverage about electricity prices, a subject that was previously rarely deemed newsworthy. The volatility of the wholesale market and the intensity of media coverage contributed to an atmosphere of hysteria over retail prices. Because retail rates during this time were set using a lagged 5-week average of wholesale market prices, customers' ability to match current information, such as their most recent bill, to the cost of the power they consumed on a given day was seriously limited. It is safe to conclude, however, that most customers were conscious of a significant increase in their cost of electricity.

Whether those customers felt that this increase was going to be a lasting one is another question, however. Throughout most of the summer there were also widely publicized efforts to encourage non-payment, in part due to an unrelated one-time refund being distributed to SDG&E customers at this time. There were also proceedings at the California Public Utilities Commission and in the State legislature directed at providing some form of relief to SDG&E customers. Eventually that relief was provided in the form of a retroactive rate freeze. All these activities must have created a large degree of uncertainty about the true final price customers would pay for their power.

Because of the uncertainty surrounding prices, due both to the complexity of the ratemaking formula and to the increasing probability that this formula would be discarded, we approach this analysis as an event study. We examine whether consumption in San Diego during key time epochs of the summer of 2000 followed a different pattern than at other times. We also account for 'shocks' to consumption from other, non-price sources that were common to all Californians by incorporating into our estimates the changes in consumption in the utilities neighboring San Diego.

We find that consumption in August 2000, the period with the highest retail rates, was about 6% lower than would be explained by non-price factors. This amounts to an average reduction of about 130 MW. The reduction in consumption varied significantly across hours of the day, however, with the largest decreases occurring in the late afternoon. Demand in these hours was around 9% lower than could be explained by non-price factors.

We also find the reduction in demand in September 2000 is comparable to that in August, even though retail rates had been significantly lowered for the majority of demand on September 1. This implies that, given the confusion surrounding prices during this period, customers reacted to the prices reflected in their most recent bill rather than to the currently relevant rates.

To further verify that retail prices played a central role in this demand reduction, we also explicitly test for a price impact on consumption in San Diego. Using a backward-looking five week moving average of price, we find that a doubling in price, which was reached in early September, should have accounted for roughly a 6% reduction in demand. These results are consistent with our previous findings. Results utilizing current rather than historic prices produced a weaker implied price response.

Although a reduction of 6% in demand may seem small when compared with some of the anecdotal stories of large scale reductions, there is much evidence to argue that this is an impressive response, given the circumstances. Customers were not receiving very clean price signals throughout this period, and were further confused by the implementation of a retroactive rate-freeze. When the dust settled, the actual increase in prices was relatively modest. If customers anticipated this outcome, they had little incentive to reduce consumption. A more plausible explanation is that consumers felt that there was some *probability* that there rates would be reduced again, but also some probability that the prices of the summer would stand. In this sense, the actual *expected* price increase was less than what would be indicated by the observed prices at the time, but greater than the actual retroactive rate that took effect in late August.

The fact that reductions during the peak demand hours of the late afternoon were closer to nine percent is also of great interest. Although this translates to about 175 MW in the San Diego system, a comparable reduction from the overall ISO system would produce nearly 3500 MW. This was the response from at most a doubling in price. In the wholesale market it is not unusual for prices to reach levels on peak that are 10 times those of off-peak prices. A program of real-time pricing applied to even half of the customers in the ISO system, if it is credibly committed to and properly understood by customers, could produce power savings that allow California to avoid rolling blackouts. As market events during 2001 have indicated, a drop of 3500 MW in peak demand can produce significant cost savings. Just as a small increase in demand can sharply drive up prices during peak periods, a small decrease in demand can conversely reduce prices very significantly.

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Tables and Figures

Table 4. Monthly Demand Response Regressions

Dependent Variable: Hourly log(SDGE demand) – log(LADWP demand).

Variable	Coefficient	Standard Error	P-Value
August, 1999	0.0206	0.0051	0.000
September	-0.0034	0.0053	0.526
October	0.0075	0.0063	0.236
November	-0.0086	0.0080	0.285
December	0.0029	0.0061	0.637
January, 2000	-0.0113	0.0054	0.037
February	-0.0164	0.0058	0.004
March	-0.0022	0.0059	0.714
April	-0.0037	0.0060	0.535
May	-0.0076	0.0071	0.279
June	-0.0163	0.0091	0.074
July	0.0037	0.0091	0.686
August	-0.0645	0.0088	0.000
September	-0.0574	0.0079	0.000
October	-0.0329	0.0084	0.000
November	-0.0375	0.0087	0.000
December	-0.0349	0.0073	0.000
log(unemployment rate) – S.D.	0.0140	0.0272	0.608
log(labor force) – S.D.	0.3746	0.1265	0.003
log(building permits) – S.D.	0.0115	0.0061	0.058
Lag log(building permits) – S.D.	-0.0181	0.0059	0.002
-log(unemployment rate) – L.A.	0.0064	0.0366	0.861
-log(labor force) – L.A.	-0.9039	0.1240	0.000
-log(building permits) – L.A.	0.0080	0.0044	0.072
-Lag log(building permits) – L.A.	0.0094	0.0034	0.006
Stage 1	-0.0063	0.0022	0.004
Stage 2	-0.0026	0.0029	0.357
Stage 3	0.0029	0.0054	0.592
Rho	0.783		
Transformed DW statistic	1.915		
R-squared	0.546		
Sample size	34,220		

* Robust (White) standard errors accounting for AR(1) error structure using the Prais-Winsten method. Variables not shown include: constant, day of week indicators, hour of day indicators by season, measure of sunlight, and weather variables. Weather variables include a quadratic function of daily mean temperatures above and below 65 degrees Fahrenheit, daily minimum and maximum temperatures, average wind speed, and average visibility for four sites in the SDGE region and two sites in the LADWP region.

Table 5. Robustness Checks of Monthly Demand Response Regressions

Dependent Variable: Hourly log(SDGE demand) – log(control group demand).

Variable	(Alt. 1)	(Alt. 2)	(Alt. 3)	(Alt. 4)	(Alt. 5)
May, 2000	-0.0305	0.0069	0.0322	-0.0018	-0.0187
	(0.0095)	(0.0078)	(0.0043)	(0.0055)	(0.0123)
June	-0.0431	0.0087	0.0369	-0.0120	0.0163
	(0.0122)	(0.0089)	(0.0055)	(0.0055)	(0.0144)
July	-0.0170	-0.0387	0.0416	0.0068	0.0349
	(0.0125)	(0.0091)	(0.0043)	(0.0057)	(0.0144)
August	-0.0672	-0.0542	-0.0073	-0.0347	-0.0695
	(0.0107)	(0.0090)	(0.0040)	(0.0053)	(0.0144)
September	-0.0521	-0.0490	0.0029	-0.0153	-0.0461
	(0.0095)	(0.0100)	(0.0047)	(0.0060)	(0.0133)
October	-0.0412	-0.0537	0.0259	-0.0020	-0.0378
	(0.0097)	(0.0095)	(0.0049)	(0.0055)	(0.0141)
November	-0.0359	-0.0319	0.0238	0.0023	-0.0325
	(0.0106)	(0.0087)	(0.0048)	(0.0055)	(0.0155)
December	-0.0303	-0.0228	0.0275	0.0109	-0.0329
	(0.0092)	(0.0084)	(0.0046)	(0.0057)	(0.0137)
CONTROL GROUP	SCE	NO	LADWP	SCE	LADWP
ECON	YES	YES	NO	NO	YES
WEATHER and INDICATOR	YES	YES	YES	YES	NO
Rho	0.762	0.860	0.798	0.769	0. 853
Transformed DW statistic	1.866	1.326	1.927	1.866	1.454
R-squared	0.512	0.937	0.536	0.505	0.021
Sample size	33,428	34,269	34,220	34,172	34,316

* Standard errors in parentheses.

Table 6. Hourly Analysis of Monthly Demand Response Regressions

Dependent Variable: Hourly log(SDGE demand) – log(LADWP demand).

Hour	May, 2000	June	July	August	September
1:00 A.M.	-0.0005	-0.0069	0.0126	-0.0570	-0.0558
	(0.0079)	(0.0094)	(0.0104)	(0.0104)	(0.0097)
2:00 A.M.	0.0011	-0.0106	0.0110	-0.0607	-0.0600
	(0.0079)	(0.0096)	(0.0106)	(0.0108)	(0.0092)
3:00 A.M.	-0.0025	-0.0204	0.0070	-0.0609	-0.0704
	(0.0074)	(0.0091)	(0.0100)	(0.0101)	(0.0085)
4:00 A.M.	-0.0060	-0.0257	0.0070	-0.0648	-0.0797
	(0.0071)	(0.0089)	(0.0096)	(0.0097)	(0.0081)
5:00 A.M.	-0.0047	-0.0265	0.0095	-0.0617	-0.0850
	(0.0072)	(0.0088)	(0.0094)	(0.0095)	(0.0080)
6:00 A.M.	-0.0093	-0.0379	-0.0051	-0.0564	-0.0739
	(0.0084)	(0.0094)	(0.0111)	(0.0098)	(0.0093)
7:00 A.M.	0.0020	0.0050	0.0200	-0.0553	-0.0791
	(0.0083)	(0.0158)	(0.0110)	(0.0097)	(0.0092)
8:00 A.M.	-0.0026	-0.0008	0.0183	-0.0465	-0.0668
	(0.0100)	(0.0154)	(0.0112)	(0.0100)	(0.0099)
9:00 A.M.	0.0006	0.0009	0.0174	-0.0435	-0.0511
	(0.0102)	(0.0141)	(0.0113)	(0.0099)	(0.0098)
10:00 A.M.	0.0088	0.0103	0.0240	-0.0389	-0.0378
	(0.0095)	(0.0124)	(0.0108)	(0.0096)	(0.0093)
11:00 A.M.	0.0043	0.0100	0.0148	-0.0472	-0.0385
	(0.0091)	(0.0118)	(0.0111)	(0.0095)	(0.0091)
12:00 P.M.	0.0038	-0.0031	0.0114	-0.0588	-0.0378
	(0.0085)	(0.0129)	(0.0109)	(0.0095)	(0.0086)
1:00 P.M.	-0.0061	-0.0066	0.0066	-0.0688	-0.0409
	(0.0082)	(0.0117)	(0.0104)	(0.0093)	(0.0084)
2:00 P.M.	-0.0118	-0.0152	-0.0040	-0.0792	-0.0466
	(0.0082)	(0.0108)	(0.0101)	(0.0092)	(0.0083)
3:00 P.M.	-0.0193	-0.0242	-0.0100	-0.0855	-0.0516
	(0.0079)	(0.0101)	(0.0099)	(0.0093)	(0.0082)
4:00 P.M.	-0.0182	-0.0300	-0.0133	-0.0908	-0.0599
	(0.0079)	(0.0095)	(0.0099)	(0.0093)	(0.0083)
5:00 P.M.	-0.0284	-0.0403	-0.0163	-0.0932	-0.0833
	(0.0092)	(0.0094)	(0.0100)	(0.0093)	(0.0099)
6:00 P.M.	-0.0412	-0.0530	-0.0177	-0.0893	-0.0772
	(0.0094)	(0.0096)	(0.0101)	(0.0095)	(0.0093)
7:00 P.M.	-0.0421	-0.0627	-0.0248	-0.0901	-0.0305
	(0.0101)	(0.0098)	(0.0100)	(0.0106)	(0.0103)
8:00 P.M.	-0.0014	-0.0479	-0.0237	-0.0606	-0.0426
	(0.0096)	(0.0098)	(0.0098)	(0.0104)	(0.0098)
9:00 P.M.	-0.0090	0.0036	0.0096	-0.0767	-0.0553
	(0.0093)	(0.0095)	(0.0099)	(0.0100)	(0.0091)
10:00 P.M.	-0.0082	-0.0055	0.0051	-0.0597	-0.0404
	(0.0085)	(0.0092)	(0.0097)	(0.0097)	(0.0090)
11:00 P.M.	-0.0006	-0.0089	0.0095	-0.0605	-0.0522
	(0.0079)	(0.0089)	(0.0097)	(0.0100)	(0.0087)
12:00 A.M.	-0.0005	-0.0041	0.0110	-0.0546	-0.0611
	(0.0076)	(0.0087)	(0.0097)	(0.0098)	(0.0090)

* Robust Standard errors with AR(1) correction in parentheses.

Table 7. Price Response Regressions

Dependent Variable: Hourly log(SDGE demand) – log(LADWP demand).

Variable	Last 5 Weeks	Past 2 Weeks - Next 2 Weeks	Last Week	This Week
Price	-0.0586	-0.0259	-0.0326	-0.0189
	(0.0065)	(0.0070)	(0.0059)	(0.0064)
log(unemployment rate) – S.D.	-0.0407	-0.0646	-0.0619	-0.0750
	(0.0154)	(0.0164)	(0.0156)	(0.0159)
log(labor force) – S.D.	0.3974	0.3953	0.4254	0.3901
	(0.0898)	(0.0969)	(0.0923)	(0.0931)
log(building permits) – S.D.	-0.0067	-0.0023	-0.0034	-0.0015
	(0.0033)	(0.0033)	(0.0032)	(0.0032)
Lag log(building permits) – S.D.	-0.0009	0.0048	0.0031	0.0055
	(0.0029)	(0.0028)	(0.0029)	(0.0028)
-log(unemployment rate) – L.A.	-0.0957	-0.1344	-0.1326	-0.1462
	(0.0239)	(0.0248)	(0.0236)	(0.0239)
-log(labor force) – L.A.	-0.5799	-0.4311	-0.4279	-0.3941
	(0.0944)	(0.0974)	(0.095)	(0.0943)
-log(building permits) – L.A.	-0.0186	-0.0246	-0.0233	-0.0251
	(0.0046)	(0.0046)	(0.0046)	(0.0046)
-Lag log(building permits) – L.A.	0.0057	0.0072	0.0072	0.0078
	(0.0045)	(0.0046)	(0.0046)	(0.0046)
Stage 1	-0.0064	-0.0075	-0.0067	-0.0069
	(0.0022)	(0.0022)	(0.0022)	(0.0022)
Stage 2	-0.0031	-0.0035	-0.0033	-0.0036
	(0.0029)	(0.0030)	(0.0029)	(0.0029)
Stage 3	0.0021	0.0015	0.0018	0.0014
	(0.0055)	(0.0057)	(0.0056)	(0.0056)
Rho	0.787	0.791	0.790	0.790
Transformed DW statistic	1.925	1.926	1.927	1.928
R-squared	0.542	0.541	0.541	0.541
Sample size	33,380	33,170	33,476	33,476

* Robust (White) standard errors accounting for AR(1) error structure using the Prais-Winsten method. Variables not shown include: constant, day of week indicators, hour of day indicators by season, measure of sunlight, and weather variables. Weather variables include a quadratic function of daily mean temperatures above and below 65 degrees Fahrenheit, daily minimum and maximum temperatures, average wind speed, and average visibility for four sites in the SDGE region and two sites in the LADWP region.

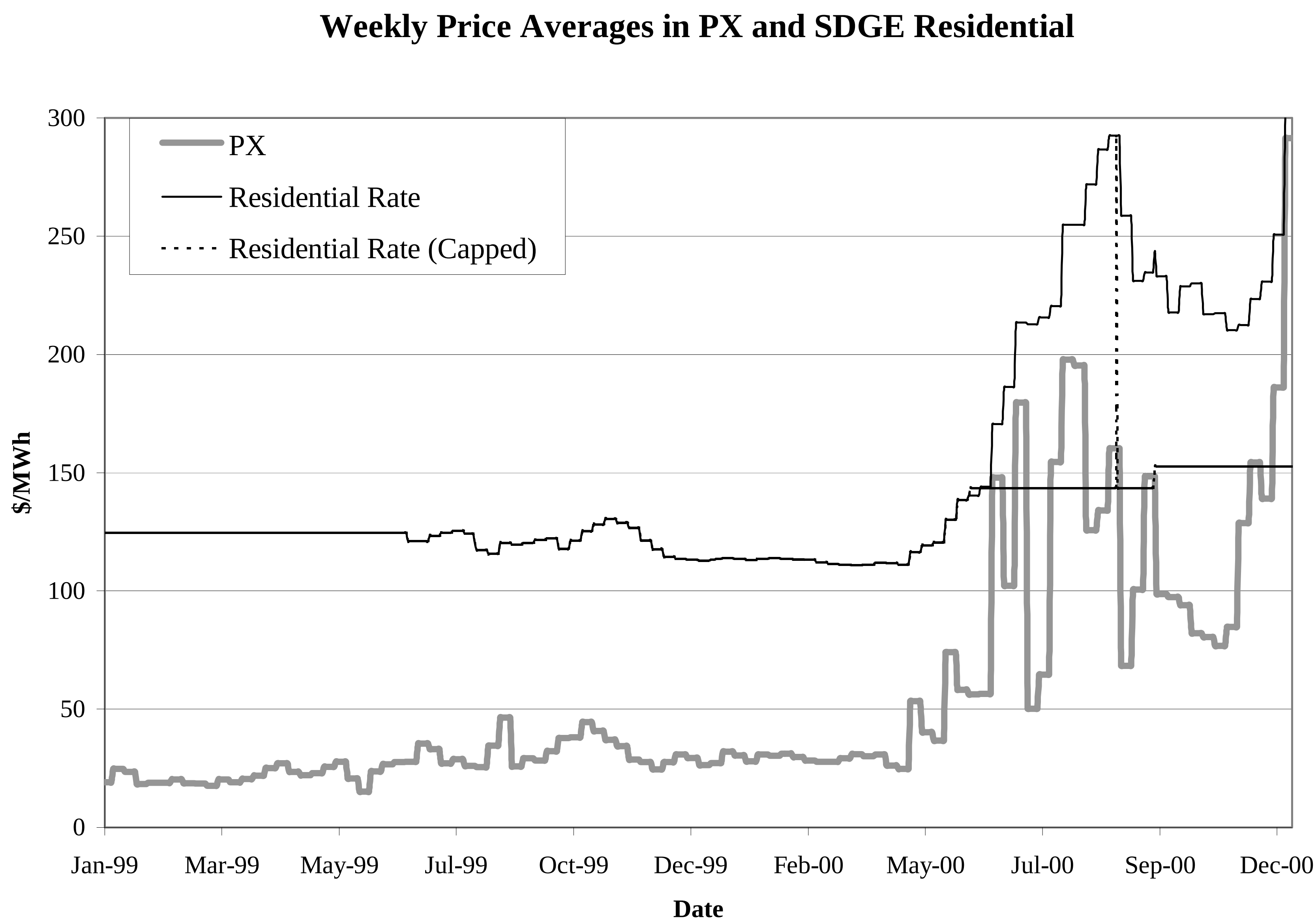

Figure 1: Five-Week Averages for PX SP15 Price and SDGE Residential Rates.

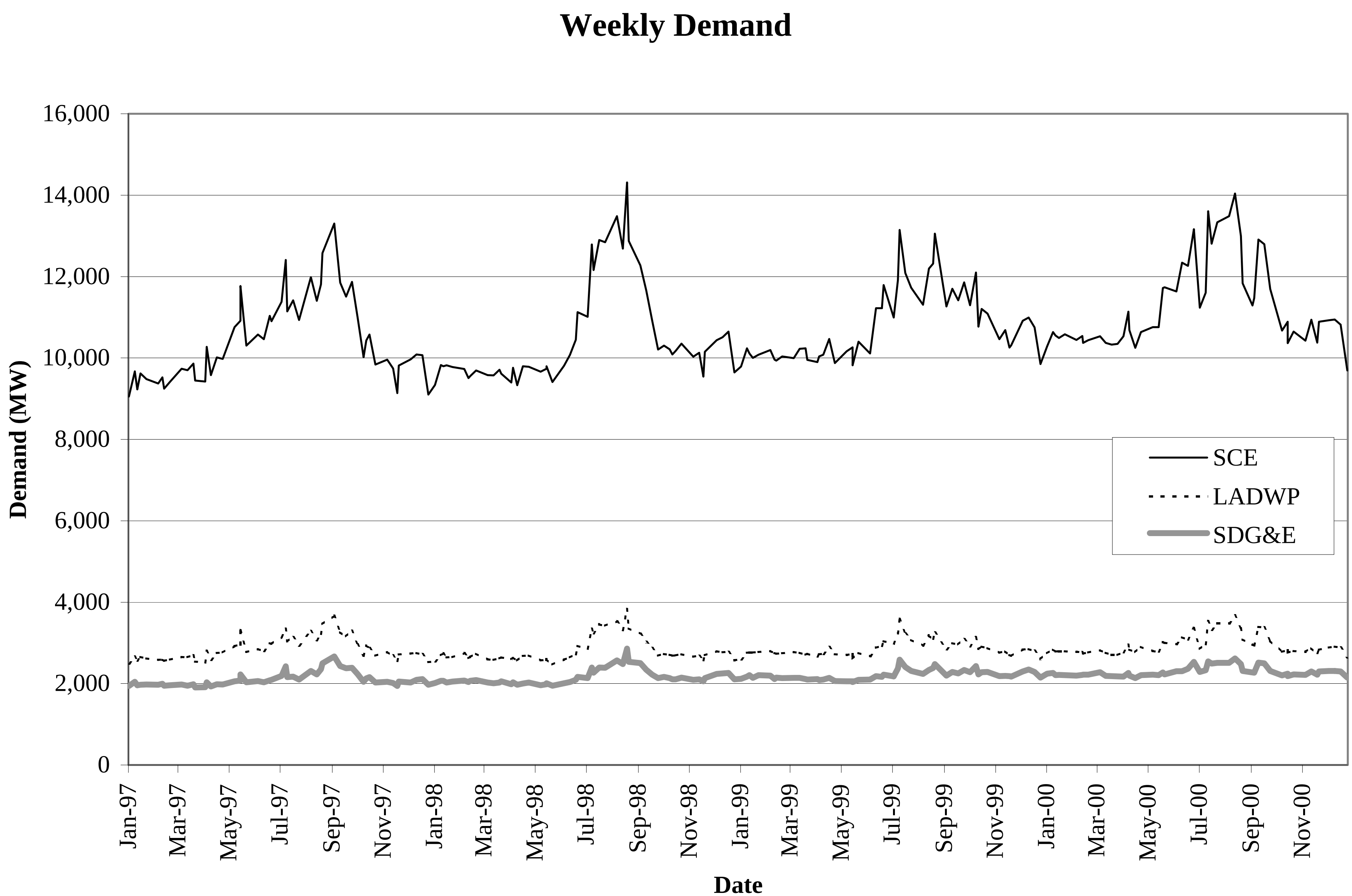

Figure 2: Weekly Electricity Demand for SDG&E, SCE, and LADWP.

Economic Variables: Labor Market

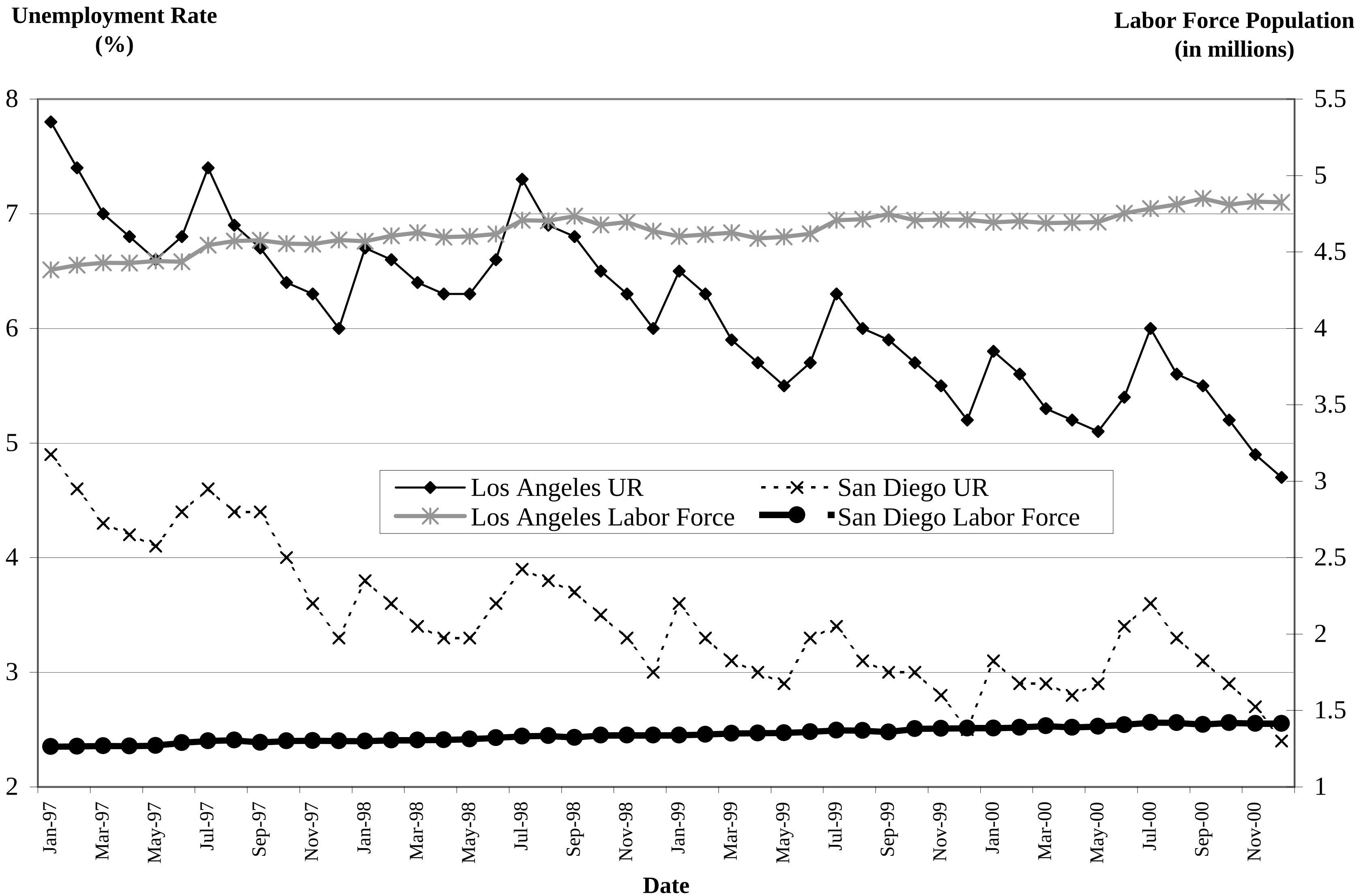

Figure 3: Unemployment Rates and Labor Force for San Diego MSA and Los Angeles CMSA from January 1997 to December 2000.

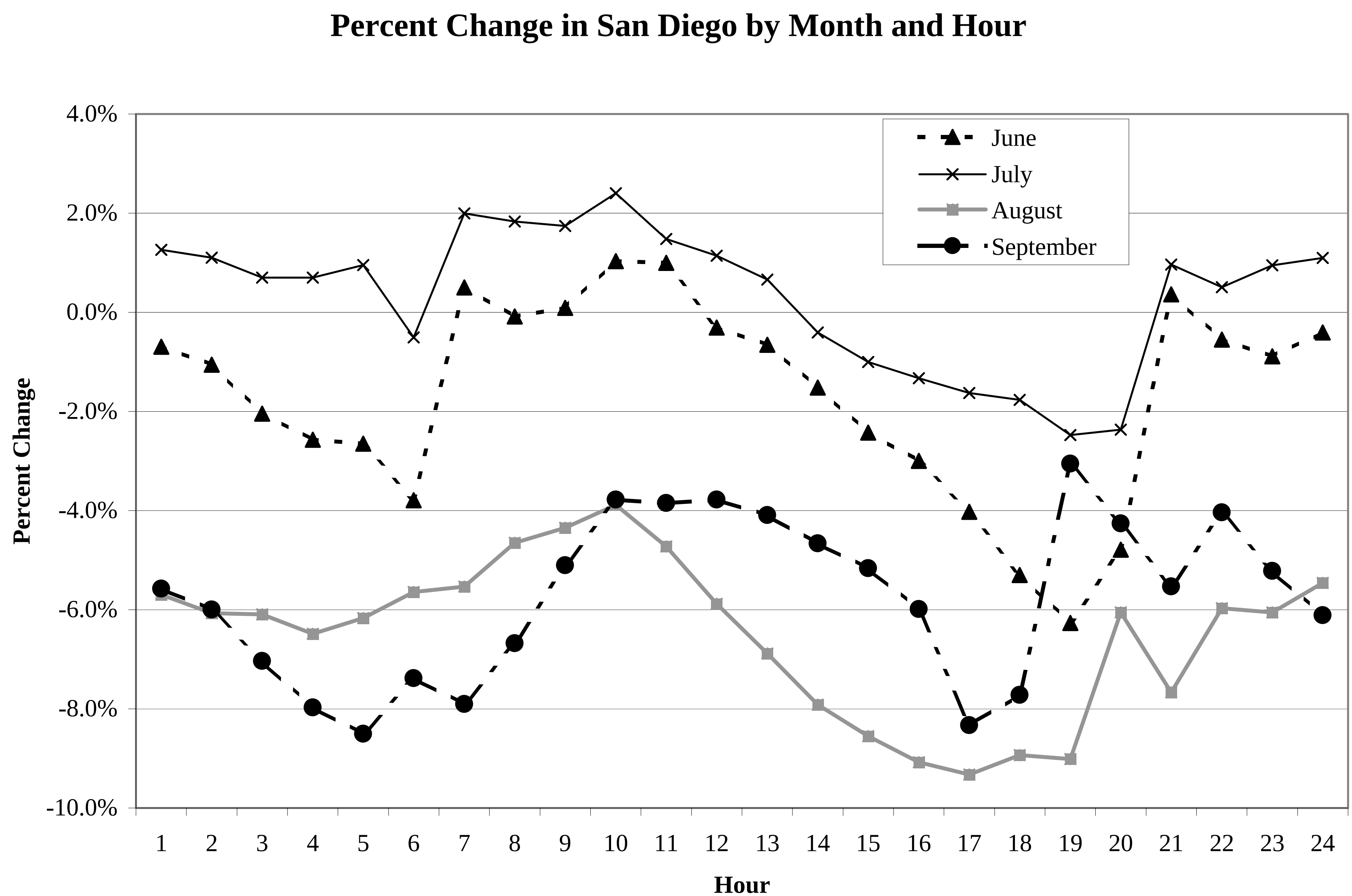

Figure 4: Percentage Change in San Diego by Month and Hour.

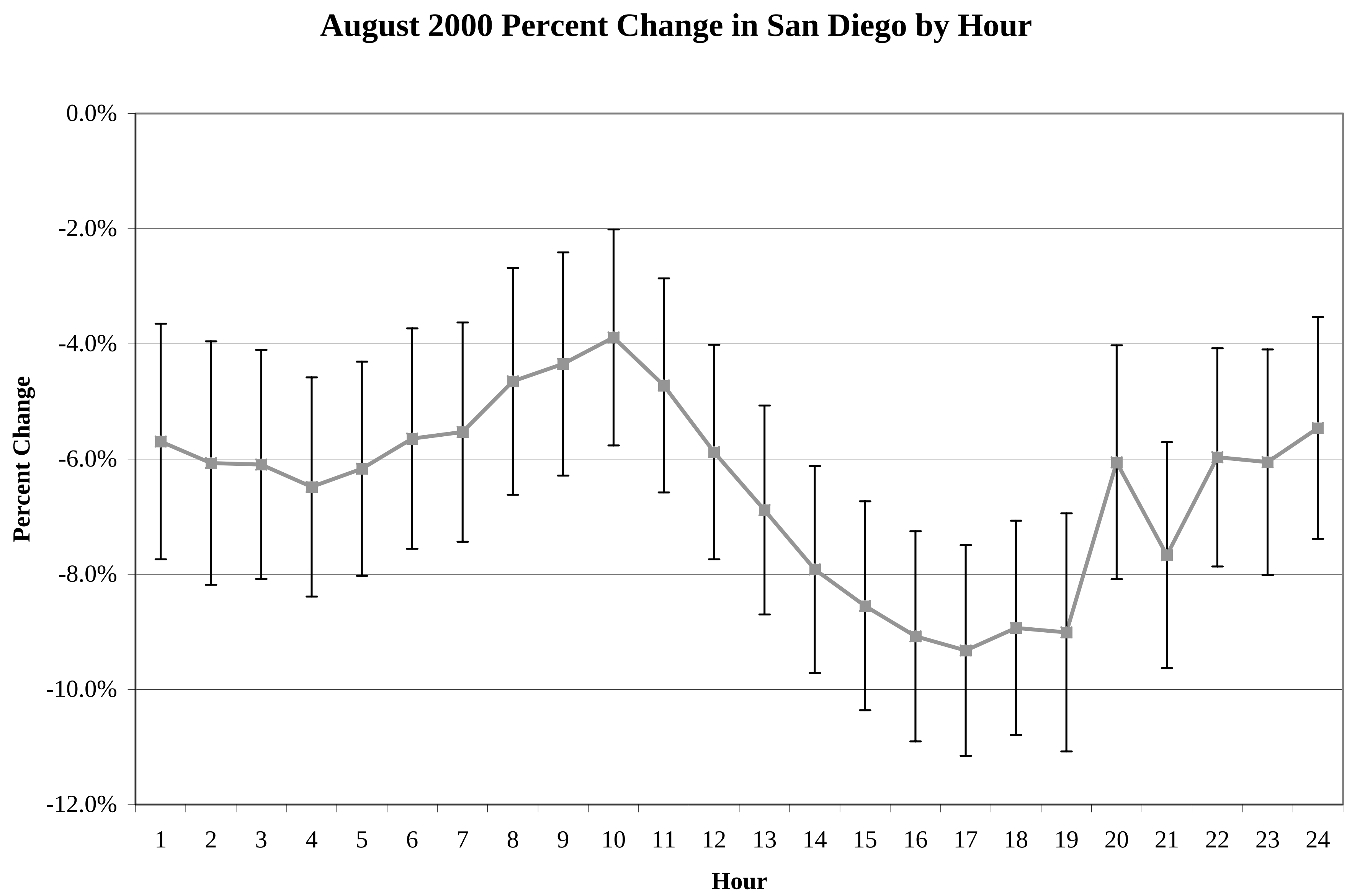

Figure 5: August 2000 Percentage Change in San Diego by Hour.