An Analysis of Residential Electricity Supply and Demand in California during the Summer of 2000

Julia A. Tuzun

Thesis submitted to the Faculty of the Virginia Polytechnic Institute and State University
in partial fulfillment of the requirements for the degree of

Master of Arts
in
Economics

Roger N. Waud, Chair

Thomas J. Lutton

Richard Theroux

July 31, 2002
Falls Church, Virginia

Keywords: Electricity, Residential Demand, Price Caps

An Analysis of Residential Electricity Supply and Demand
in California during the Summer of 2000

Julia A. Tuzun

ABSTRACT

Prior to 1996, roughly 70% of electricity service in California was provided by investor owned utilities (IOUs). The IOUs operated as monopolies in their respective service territories, performing all of the functions necessary to generate and deliver electricity to the consumer. In exchange for service, the IOUs were paid a regulated rate which was designed to recover their cost of providing the service plus a reasonable return on their investment. In 1996, California changed the way electric service was provided in order to make it more competitive. Among the changes, utilities would procure their supplies at market prices in an auction or spot market; residential customers could choose their electric supplier; and residential rates were frozen at 10% below their June 1996 levels. The rate freeze was to remain in effect until the later of March 31, 2002, or the date the IOUs fully recovered certain expenses that were still on their books (i.e., stranded costs). The restructured market commenced operations on March 31, 1998.

During the summer of 2000, California experienced record increases in wholesale prices and supply shortages that ultimately resulted in a number of rolling blackouts. Most of California's residential customers were unaffected by the increased wholesale prices because their rates remained frozen. Regulators and others who have studied what went wrong during the summer of 2000 in California agree that the increase in wholesale prices was due to a combination of factors, one of which was the residential rate freeze. This thesis proposes to show how fixing the price of electricity resulted in excess demand and to quantify the size of the excess. This thesis also shows how much of a price increase would have been needed to prevent the shortages.

TABLE OF CONTENTS

TABLES AND FIGURES

Section 1 – Purpose of the Study

During the summer of 2000, California experienced record wholesale price increases and supply shortages that ultimately resulted in rolling blackouts. Most of California's residential customers were unaffected by the high wholesale prices because their rates remained frozen at 10 percent below their 1996 levels. Regulators and others who have studied what went wrong that summer agree that the increase in wholesale prices and the supply shortages were due to a combination of factors, one of which was the residential rate freeze. As a regulator, it would have been nice to know, prior to implementing the price freeze, just how responsive residential demand is to a change in the price and to use this information to predict what would happen under various scenarios if supply were allowed to respond to market forces and demand was not. Such information, even in hind sight, could be useful in underscoring the need for the market to send clear and accurate price signals.

Section 2 - Overview of California's Electric Industry

Section 2.1 - Regulated Regime:

Prior to 1996, electricity service in California was provided by regulated utilities that operated as monopolies in franchised geographic areas. The utilities performed all of the functions involved in the supply of electricity, i.e., they owned and operated the power generating plants, the high voltage transmission systems and the distribution lines that delivered electricity to consumers. They also performed all aspects of the business of electricity supply, such as retailing and marketing, customer service, metering and billing.[1]

Section 2.2 – Restructured Market:

In 1993, the California Public Utilities Commission began exploring ways to restructure the electric system in response to high electricity prices. At the time, residential rates reached 11.8 cents/kWh, 40% higher than the national average and the tenth highest rate in the nation.[2] The high prices sparked fears that firms might leave the state and thus slow the state's economic expansion. [3] In September, 1996, after numerous hearings and negotiations, the California legislature unanimously enacted and the Governor signed into law Assembly Bill 1890 (AB1890). The goal of AB 1890 was to make the state's electric industry more competitive. The key provisions of the law are:

- Retail customers could choose their electricity service provider. Customers that elected not to choose received default service from their local utility.
- The three largest utilities - Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) - divested all of their fossil-fueled generation but retained their nuclear

[1] California Independent System Operator. California ISO Annual Report on Market Issues and Performance, June 1999.
[2] California Energy Commission. 1994 Electricity Report.
[3] Ibid 2.

and hydro generating plants and existing long-terms contracts.

- The utilities retained ownership of their transmission facilities but were required to turn operational control of these facilities over to a non-profit, independent entity called, Independent System Operator (ISO). This was designed to ensure fair and impartial access to the transmission system by all generators and to maintain reliability. The utilities retained ownership and operational control of their distribution lines.
- The law created a Power Exchange (PX) which is an auction or spot market for the buying and selling of electricity. The three large utilities were required to sell the power from their remaining generation assets into the PX and then buy the power back to meet their default service obligations.[4] Other power producers could at their option participate in the PX.
- All retail rates were frozen while the rates for residential and small customers were fixed at 10 percent below their 1996 levels.[5] The retail rate freeze was to remain in effect until the later of March 31, 2002, or the date the utilities recovered certain costs (commonly referred to as stranded costs) that were still on their books.[6] See next paragraph for a discussion of stranded costs.
- The utilities would recover their stranded costs through a Competition Transition Charge (CTC) imposed on all ratepayers. The CTC is equal to the retail price of electricity minus the suppliers' cost of purchasing or generating the electricity and delivering it to the consumer. To the extent wholesale costs were low, stranded cost recovery would be quicker.[7] As mentioned above, both the CTC and the rate freeze would expire on the earlier of March 31, 2002, or the date the utility fully

---

[4] San Diego Gas & Electric Company, et al. Order Proposing Remedies for California Wholesale Markets, 93 FERC 61,121, November 2000.

[5] Staff Report to the Federal Energy Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities. Part 1 of Staff Report on U.S. Bulk Power Markets. November 1, 2000.

[6] Source California Energy Commission. July 1998, page 4. About 80% of the stranded costs are comprised of nuclear generation capital costs and payments under long term contracts to independent power producers or cogenerators. The CTC also would recover expenses for retaining employees displaced as a result of restructuring. The expectation was that the rates would be low and that recovery would be relatively quick. The wholesale price increases made stranded cost recovery impossible.

[7] Ibid 5.

recovered its stranded costs. In 1999, SDG&E completely recovered its stranded cost and, hence, was not bound by the rate freeze during the summer of 2000.

Section 2.3 - First Two Years of Operation

California's restructured market commenced operations on March 31, 1998. The Annual Report on Market Issues and Performance issued by the ISO's Market Surveillance Unit says that, during the first year of operation, the ISO had to address a number of challenges, including software issues, gaming problems, market design flaws and market power issues. Despite these problems, however, the market evolved and prices appeared to track expectations.[8] From 1998 until April 2000, wholesale prices averaged $33/MWH, which was close to the marginal cost of power production.[9] Since retail rates were capped at roughly 9.34 cents per kilowatt-hour, there was ample room for the utilities to recover both the wholesale and the stranded costs. [10]

Section 2.4 - Summer of 2000

During the summer of 2000, wholesale prices jumped dramatically particularly in May and June. The monthly average unconstrained market clearing price for May in the PX's day a-head market represented a 100 percent increase over May 1999.[11] On several occasions in May and June, wholesale prices reached or neared $750/MWH and on June 28th prices reached an all time high of $1099 for five hours.[12] Also in May and June, there were supply shortages due to a prolonged heat wave and a number of generation outages. As a result, on 38 separate occasions, which is far more than in any other year, the ISO issued emergency notices or appeals for customers to voluntarily shed load. On May 22, the ISO called for utilities to curtail service to several hundred large customers; and on June 14, PG&E was required, for the first time in its history, to interrupt service to

---

[8] Ibid 5.
[9] Ibid 5 and California Energy Outlook, Electricity and Natural Gas Trends Report. September 2001.
[10] One thousand kilowatt hours equals one megawatt hour.
[11] The unconstrained price is the price without transmission congestion charges.
[12] Ibid 5 and California ISO Report on California Energy Market Issues and Performance, May-June, 2000, Special Report. August 10, 2000.

nearly 95,000 residential and small commercial Bay area customers.[13] The high wholesale prices continued throughout the year as did the need for the ISO to curtail certain loads.[14] Average PX wholesale prices were: $47/MWH in May, $120/MWH in June, $106/MWH in July and $166/MWH in August. Prices remained remarkably high even during October ($100/MWH) and November (about $140/MWH through November 19th), both of which are relatively low-load months.[15]

SDG&E's customers felt the full impact of the May and June increase in wholesale prices since their rates were no longer frozen. As a result, its customers saw their bills increase by as much as 200 to 300 percent over the prior year.[16] The increases in residential rates were short-lived because, on August 30, 2000, the California legislature voted to establish a 6.5 cents/kWh price cap for SDG&E's customers. The cap was retroactive to June 2000 and was to remain in effect through 2000.

Section 2.5 - What Went Wrong?

Regulators and others who have studied what went wrong during the summer of 2000 in California agree that the increase in wholesale prices was due to a combination of supply, demand and market factors. This thesis summarizes only the main factors in sufficient detail to shed some light on the data used in the analysis.

The supply and demand factors are best illustrated in the context of Table 1 below which summarizes the ISO's summer forecast of demand (i.e., peak load) and supply (i.e., generation and net imports). For the summer of 2000, the ISO projected that exceptionally high load conditions, normally precipitated by high temperatures, could

[13] California Energy Commission. California Energy Outlook, Electricity and Natural Gas Trends Report, Staff Draft, September 2000.
[14] Ibid 5.
[15] Joslow, Paul and Kahn, Edward. A Quantitative Analysis of Pricing Behavior In California's Wholesale Electricity Market During the Summer 2000, November 21, 2000. The decline in the average price reflects the fact that the FERC lowered the price cap and that utilities were bidding close to the cap.
[16] Kahn, Michael, and Lynch, Loretta. California's Electricity Options and Challenges Report to Governor Gray Davis. May 24, 2002.

lead to a capacity shortage of about 3,940 MW. [17] Unfortunately, that summer, California experienced the fourth hottest summer in 106 years while the desert southwest experienced the second hottest summer in 106 years.[18] As a result, demand hit record levels in May, June and October.[19] The peak demand for the summer 2000 is shown in Table 2.

Table 1 - Projected California ISO Peak Loads and Resources

Load Condition	Peak In-Area Load	Generation	Net Imports	Excess(+) or Deficiency (-)
Normal	46,250	38,000	8,400	150
High	48,940	38,000	7,000	-3,940

Table 2 - Actual Monthly Peak Loads for ISO Control System (MW)

May	June	July	August
39,808	43,630	45,245	45,494

Section 2.5.1: Supply and Demand Factors:

On the supply side, California's investment in new capacity had not kept pace with the dramatic growth in demand and, as a result, reserve margins shrank.[20] Over the past 15 years, there had been very little investment in generation whereas robust population and economic growth caused demand to increase by 37% in the 1980s and15% in the 1990s. Wolak[21] reports that, in the first eight months of 2000 relative to

[17] Ibid 5.
[18] Ibid 5 and California Power Exchange Corporation, Compliance Unit. Price Movements in California Electricity Markets, September 29, 2000.
[19] Ibid 18. It should be noted that the hottest summer was followed by the coldest winter.
[20] Ibid 18. Reserve margins dropped to a thin 4% to 6% compared to the forecast of 17% to 20%.
[21] Wolak, Frank; Nordhaus, Robert; and Shapiro, Carl. Market Surveillance Committee of the California Independent System Operator. An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets. September 6, 2000

the same months in 1999, demand in California grew by approximately 5% due to a robust state economy. He concludes that the failure to construct new transmission and generation capacity within the state to match this demand growth increased the frequency of periods of generation capacity shortages and opportunities for generation unit owners to exercise market power.

In May and June, reserve margins were further reduced by an unusually high number of planned and unplanned outages. According to the California ISO's August report, during the May 22 price spike, about 22% of the state's nearly 17,000 MW of thermal generation that was recently divested by the state's IOUs was unavailable due to scheduled maintenance and forced outages. During the June spikes, an average of 10% of this generation capacity was unavailable due to scheduled maintenance and forced outages.[22] The explanations for the increase in outages include: (1) the age of California's plants (82% are more than 30 years old); (2) plants owners were foregoing maintenance in order to meet demand; and/or (3) plant owners were withholding capacity in order to manipulate the price.

As shown in Table 1, California relies on imports of electricity to meet its demand. A significant portion of the imported power is generated by hydro facilities in the Pacific Northwest. However, water levels in that region were much lower than expected, thereby reducing hydroelectric availability.[23] Additionally, to protect the salmon spawning activity through September, water was held back in June and July at reservoirs for use in later months. Hydro-generation from outside of California was 8.6 % below 1999 levels in May and 23.2 % below 1999 levels in June. It should be noted that the same dry spell affected California. As a result, California hydropower output in 2000 was about 40% less than it had been in 1999.

[22]Ibid 12, California ISO.
[23]Ibid 18, California Power Exchange.

Section 2.5.2: Production Cost Factors:

During the summer 2000, the price of natural gas, the fuel for 53% of California's generating units, was double what it was for the same months in 1999. The California ISO states that about 20% of the increase in overall electricity costs can be attributed to the rapid rise in natural gas prices. In addition, the market value of nitrogen oxides (NOx) air emission credits necessary to run gas units rose from about $2/pound of NOx in early 2000 to over $40/pound at the end of August. The FERC estimated that the increased natural gas and NOx prices raised the marginal cost of running a combined cycle generation unit by approximately $64/MWH.[24]

Section 2.5.3: Market Rules:

As mentioned earlier, PG&E, SCE and SDG&E were required to purchase their power through the PX and had little or no ability to enter into forward long term contracts for energy. Thus, when the spot market prices increased, the IOUs had no option but to purchase the high priced power.[25]

The California Energy Commission states in its Staff Draft Report that "a key element missing from California's electricity market design is demand responsiveness – consumption that varies with market prices". There appears to be unanimous agreement on this point. With the rate freeze in place, there was no price signal for the residential customers to respond to; and, in the case of SDG&E, customers did not have the means to respond since they did not discover the prices until long after the fact. Moreover, any opportunities they had to respond were squashed by the retroactive cap that was enacted on August 30. The next sections try to determine what the price signal and response could have been.

[24] Ibid 5.
[25] Ibid 5, 12 and 18.

<u>Section 3 - Model Specification and Methodology</u>

Section 3.1 - Model Specification

Section 3.1.1: Demand Equation:

There is general agreement among the industry, regulators and academics that residential electricity demand is a function of some economic variables, such as the price of electricity, the price of substitutes and the level of income; and some non-economic variables such as weather, population, and housing stock. The California Energy Commission (CEA), the agency charged with analyzing demand for each utility area, states that its forecasting model uses data on economic growth, population, climate in various regions, characteristics and saturation of energy using appliances and equipment, and changes in energy utilization and regulatory conditions. With regard to residential demand, the CEA says that three-quarters of the increase in residential demand comes from population growth while the remaining one-fourth is due to growth in personal income and new housing. The CEA also states that summer temperatures are the single biggest variable in determining whether actual peak demand will be higher or lower than the long-term trend.

My analysis assumes that the quantity of electricity demanded by residential customers is a function of the price of electricity, income per capita, population, households with central air conditioners, households with space heaters, heating and cooling degree days and the price residential customers pay for the substitute fuel, natural gas. My demand function is:

Ln(Qdjt) =

A0+A1*ln(Pejt)+A2*ln(Yjt)+A3*ln(Popjt)+A4*ln(Hacjt)+A5*ln(Hhjt)+A6*Djt+

A7*ln(Grjt) +ujt,

Where

Qd = total demand

Pe = average residential price of electricity

Y = Income per capita

Pop = Population

Hac = Households with central air conditioners

Hh = Households with space heaters

D = Heating and cooling degree days

Gr = Residential price of gas

u = Error term

j = Utility reporting the data

t = the date of the data

The average residential price of electricity was obtained by dividing the total revenues received from the residential customers each month by residential demand for that month. Over the years, there has been considerable debate over whether demand models should use average prices or marginal prices.[26] I have chosen to use average prices because marginal prices were not available. In addition, studies have shown that customers do not respond to the marginal prices because (1) most do not know what the marginal prices are and (2) even if they did know, most do not have meters and, therefore, are unable to respond to the marginal price. Customers can and do respond to their total electric bills which, in a sense, might be viewed as an average.[27]

Per Capita income is the average for the region and stated in 1977 dollars.

The population variable is the total for the region.

Of all of the appliances that use electricity, I have included central air conditioners and space heaters namely because they are two of the largest users of

[26] See Halvorsen, Robert. Econometric Models of U.S. Energy Demand. Lexington Books. 1978 and Bohi, Douglas. Analyzing Demand Behavior, A Study of Energy Elasticities. Published for Resources for the Future, Inc. by Johns Hopkins University Press. 1981.

[27] The price of electricity is itself a function of the quantity demanded because residential customers face a schedule or block of prices which decline as usage increases. The price of the marginal unit purchased within each block is constant but decreases in subsequent blocks. The average price paid for all units is equal to the marginal price only in the first block. Thereafter, the average price decreases as the quantity

electricity. The air conditioner and space heater variables are stated on a per household basis and, therefore, might also be indicative of the growth in the number of households in the particular region.

The raw heating and cooling degree day data was by monitoring station or zone. About half of the zones were in a single utility service area while the other half were in multiple utility service areas. In the cases where the zones fell into more than one service area, I first determined which zones were in which service area. I, then, weighted the heating and cooling degree days in those zones by the number of households in the zone and assigned the resulting number to the respective service area. Degree days are the total of the heating and cooling degree days for the given time period in the region. To calculate a heating or cooling degree day, you add the day's high and low temperatures and divide the result by 2. If the resulting number is less than 65, you have a heating degree day. Conversely, if that number is greater than 65, you have a cooling degree day.

There are only a few applications for which natural gas is a substitute for electricity. These include heaters and stoves. The gas variable is included to see the extent to which this is true. The residential gas prices are historic averages and are stated in dollars /thousand cubic feet. For comparison purposes, I have restated the prices on a dollars/kWh basis. In making the conversion, I assumed that, with a heat rate of around 10,000 Btu/kWh, a natural gas price of $10/million BTU translates into a 10 cents/kWh electricity cost for a 10,000 Btu electric generating plant. [28]

Section 3.1.2: Supply Equation:

My analysis assumes that supply equals demand. This assumption is appropriate because, until 1996, residential supply was determined by the regulators and not the market. The regulators and the utilities take great pains to determine the best estimate or forecast of demand. Once the demand forecast is agreed upon, the regulators direct the

---

demanded increases.

[28] Taylor, Jerry and VanDoran, Peter. Policy Analysis No. 406. California's Electricity Crisis, What's Going On, who's to Blame and What to Do. July 3,2001.

utilities to be prepared to meet that level of demand. After 1996, my assumption still holds true since the job of insuring that supply equaled demand shifted to the ISO and the PX. My analysis also assumes that supply is a function of the residential price of electricity because this is the amount the regulator has determined is sufficient to recover the utility's allowable costs.[29] My analysis further assumes that the quantity supplied is a function of the fuel, natural gas, because 53% of California's generating units are gas fired. The last variable is a time index which reflects the twelve months of the year.

My supply function is as follows:

Ln (Qsjt) = Bo+B1*ln(Pejt)+B2*ln(Gujt)+B3*T+vjt,

Where

Qs = Quantity supplied

Pe = Price of electricity

Gu = Price paid by the utilities for natural gas

T = Time

e = error term

j = utility reporting the data

t = date of the data reported

The electricity price variable in the supply equation is the same as the price variable in the demand equation.

As noted above, there are many other cost components which, ideally, should have been included in the model, e.g., the cost of other fuels such as nuclear, oil and coal, and other costs such as labor and operation and maintenance expenses. However, natural gas was the only fuel for which historical price data was consistently available for all of

[29] The cost of generating electricity is generally a function of a variety of fixed and variable costs and expenses such as the cost of capital, operation and maintenance expenses, administrative and general expenses, depreciation, taxes and fuel. To determine the residential rate, the utility submits to the regulators an estimate of what it would cost to provide the agreed upon level of service and proposed residential prices that would recover those costs. The regulators review the utility's estimates of its costs and the proposed schedule of prices, adjusting them for errors, omissions or excesses. The final price approved by the regulators is the price of electricity the residential customer will face.

the utilities included in my study. In addition, a complete and consistent historical data set of the other costs and expenses incurred by some of the utilities used in this study does not exist.

Section 3.2: The Data Sets

- I collected pooled time series data for the years 1980-2000 for the areas serviced by PG&E, SCE, SDG&E, SMUD and LADWP because these utilities provide roughly ninety-six percent of the end use electric service in California. The categories of data are listed below:
- Total monthly residential demand by utility in kilowatt hours (kWh)
- Total monthly revenues received from the residential sector by each utility
- Average monthly price per kilowatt hour (Total monthly residential revenues/total monthly residential demand)
- Annual income per capita in 1977 ($) for each utility service area
- Annual population by utility service area
- Annual number of households by type of household by utility service area and by zone
- Annual number of central air conditioners per household
- Annual number of space heaters per household
- Heating degree days by zone by month
- Cooling degree days by zone by month
- Average monthly price of natural gas paid by all utilities in California ($/thousand cubic feet)
- Average monthly price of natural gas paid by all residential customers in California ($/thousand cubic feet).

The demand, revenue, income, population, air conditioner, space heater and household data are from the California Energy Commission; the natural gas prices from the Energy Information Agency; and the heating and cooling degree data from the Western Regional Climate Center.

For the years 1980 through 1984, there were quite a few months with missing or incorrect data. As a result, in order to have a consistent pooled timed series, I eliminated the months where one or more of the utilities had missing or incorrect data. Since the income, air conditioning, space heater and population data were reported on an annual basis, I treated data as a constant for each month of the year for which it was reported. All of the data, except for the natural gas prices, are by utility service area. Therefore, I assumed that the natural gas prices faced by each utility were the monthly averages for the state.

Section 3.4: Methodology and Results:

The model I have developed has two endogenous variables - quantity demanded, which is equal to quantity supplied, and the price of electricity - and seven exogenous variables - income, population, households with central air conditioners, households with space heaters, total degree days, residential price of gas, utility price of gas and time. The model is a simultaneous equation system because, in order to reach an equilibrium solution, Q and P must be jointly determined. In order to obtain consistent parameter estimates, I calculated the reduced form of the model by expressing price as a function of all of the exogenous variables in the system. The model and the reduced form of the model are shown below.

Section 3.4.1: The Model is as follows:

Demand: ln(Qdjt) =

Ao+A1*ln(Pejt)+A2*ln(Yjt)+A3*ln(Popjt)+A4*ln(Hacjt)+A5*ln(Hhjt)+A6*(Djt)+A7*ln(Grjt)+ujt

Supply: ln(Qsjt) = Bo+B1*ln(Pejt)+B2*ln(Gujt)+B3*T+vjt, **where**

ln(Qdjt) = ln(Qsjt)

The Reduced form calculations for ln(Pejt) are as follows:

B0+B1*ln(Pejt)+B2*ln(Gujt)+B3T+vjt =

A0+A1*ln(Pejt)+A2*ln(Yjt)+A3*ln(Popjt)+A4*ln(Hacjt)+A5*ln(Hhjt)+A6*(Djt)+A7* ln(Grjt)+ujt

(B1-A1)ln(Pejt)= (A0-B0)+A2*ln(Yjt)+A3*ln(Popjt)+A4*ln(Hacjt)+A5*ln(Hhjt)+ A6*(Djt)+A7*ln(Grjt)-B2*ln(Gujt)-B3T+(ujt-vjt)

Ln(Pejt) = (A0-B0)/(B1-A1)+(A2/B1-A1)*ln(Yjt)+(A3/B1-A1)*ln(Popjt)+(A4/B1-A1)*ln(Hacjt)+(A5/B1-A1)*ln(Hhjt)+(A6/B1-A1)*Djt+(A7/B1-A1)*ln(Grjt)-(B2/B1-A1)*ln(Gujt)-(B3/B1-A1)*T+(ujt-vjt)

Ln(Pejt) = (A0-B0)/(B1-A1)+(A2/B1-A1)*ln(Yjt)+(A3/B1-A1)*ln(Popjt)+(A4/B1-A1)*ln(Hacjt)+(A5/B1-A1)*ln(Hhjt)+(A6/B1-A1)*(Djt)+(A7/B1-A1)*ln(Grjt)-(B2/B1-A1)*(Gujt)-(B3/B1-A1)*T+(ujt-vjt)

For convenience,

ϕ0 = A0-B0/B1-A1

ϕ1 = A2/B1-A1

ϕ2 = A3/B1-A1

ϕ3 = A4/B1-A1

ϕ4 = A5/B1-A1

ϕ5 = A6/B1-A1

ϕ6 = A7/B1-A1

ϕ7 = -B2/B1-A1

ϕ8 = -B3/B1-A1

z = ujt-vjt

The reduced form for ln(Pejt) is

Ln(Pejt) =ϕ0+ϕ1*ln(Yjt)+ ϕ2*ln(Popjt)+ ϕ3*ln(Hacjt)+ ϕ4*ln(Hhjt)+ ϕ5*(Djt)+ ϕ6*ln(Grjt)+ ϕ8*ln(Gujt)+ ϕ9*T+z

In order to estimate Pejt-hat, I used the data sets and regressed the actual price of electricity on all of the exogenous variables in the reduced form equation for Pejt. The Summary Output for that regression is shown in Table 3.[30] The regression results show that about 66% of the total variation in Pejt is explained by the exogenous variables. The F statistic is 205.27 with a Significance F of 1.9629E-191 rule out the possibility that the eight coefficients are equal to zero and lead to the conclusion that the model is useful in explaining the quantity demanded and supplied. The t-statistics and p-values for all of the coefficients, except income per capita, degree days and time, indicate that there is a direct relationship between these variables and the price of electricity. I used the coefficients that were generated by the regression, and shown in Table 3, the data sets and the Pejt reduced form equation to calculate Pejt-hat.

Section 3.4.2: Results of Two Stage Least Squares

Both the supply and demand equations are over identified because the number of excluded exogenous variables exceeds the number of endogenous variables minus one. Therefore, I used two stage least squares to estimate the supply and demand functions. In the first stage, I estimated the quantity supplied by regressing Qsjt on ln(Pejt-hat), which was derived using the reduced form equation, and the other variables in the supply equation above. The results of that regression are shown in Table 4. The F statistic of 172.33 and the Significance F of 9.664E-108 indicate that the fitted model is helpful in explaining the variability in supply. The high t-statistics and the small p-values for all of the variables in the supply equation indicate that the variables are significant variables in predicting supply. The sign of the price coefficient is positive, indicating an upward sloping supply curve. The sign for ln(price of utility price of gas) is negative, as it should be because an increase in the price of the input gas translates into a rate decrease for the supplier. I used the coefficients derived from this regression to calculate ln(Qsjt)-fit.

In the second stage regression, I estimated the quantity demanded by regressing

[30] The tables and figures are on page 23 onwards.

ln(Qdjt) on the fitted value of price that was calculated using the reduced form and all of the other demand variables. The Summary Output of this regression is shown in Table 5. The high R-square of 0.974, the F statistic of 4504.64 and Significance F of zero confirm that the model is useful in explaining the demand for electricity. The t-statistics and the low p-values for most of the variables indicate that these variables have a significant role in explaining quantity demanded. The key variables are population, households with central air conditioning and degree days. This result is slightly different from, but not inconsistent with the California Energy Commission's claim that three quarters of the growth in demand is due to population while the balance is due to growth in housing and income. Finally, all of the signs of the coefficients are consistent with economic theory. In particular, the price coefficient is negative indicating a downward sloping demand curve. Also, the positive coefficients for income per capita, population, households with air conditioning and heaters, and degree days say that an increase in any of these variables leads to an increase in demand. Because all of the variables are expressed in log form, the coefficients are the elasticities of demand. The elasticity of demand with respect to price is the price coefficients of -0.2304, which means that a one percent increase in the price would lead to a 0.2304 percent decrease in the quantity demanded. A decrease of this magnitude implies that the market for residential electricity is relatively inelastic. According to the California Energy Commission, residential electricity demand is indeed inelastic.

Section 4 Analysis of Year 2000 Data

As discussed earlier, demand in California increased substantially during the summer of 2000 due to economic growth and an extended heat wave. Over this period, most residential rates remained frozen at 10 per cent below their June 1996 levels. Also, during this period, wholesale prices rose to record levels due to rapid increases in the price of natural gas, the fuel for more than half of the generators. Since all but SDG&E's retail rates remained frozen, the utilities were forced to eat the retail ratepayers' share of the shortfall, a circumstance that pushed them almost to the brink of bankruptcy. Amid this atmosphere, supply shortages forced the utilities to declare repeated supply emergencies and on two separate occasions to implement rolling blackouts.

Section 4.1: The Data Sets:

Table 6 shows the data sets for the year 2000 that were used in this analysis. The consumption data, shown in the column labeled "Quantity", is expressed in megawatt hours for each utility service area and is the actual for the utility for the month. One megawatt hour is equal to 1000 kilowatt hours. The column labeled Average Electricity Price is the average price paid by consumers in a particular service area and is stated in cents per kilowatt hour. The prices consumers paid in each of the service areas, except SDG&E's, were the regulated prices and, thus, were the frozen or capped prices. [31] The variation in these prices, as shown in Table 6, is because, as mentioned above, residential rates are block rates which vary with the level of consumption and, for any one of a number of reasons, consumption within each block also varies. The net result is some slight variation in the averages.

The income, population, air conditioning, heater and degree day data are the actual amounts for the year. Since monthly data was not available for these variables, I treated the annual amounts as a constant for each month of the year. I converted the gas

[31] In this section, I will sometimes refer to the frozen prices as capped prices.

prices into cents per kilowatt hour by assuming a heat rate of 10,000 BTU per kWh.[32]

Section 4.2: Methodology:

As stated above, the coefficients that were derived in the previous section are logs and, thus, are the elasticities of those variables with respect to supply or demand. The data and the variables that were used to calculate the coefficients represent a cross section of the companies in the State of California and, thus, describe the system-wide effect that changes in the any one of the variables may have on quantity supplied or demanded. Because of this, my analysis of the year 2000 data will be on a state wide basis as opposed to utility by utility.

The methodology I used to determine whether fixing the price of electricity resulted in excess demand consisted of the following. First, I calculated the monthly average for each variable listed in Table 6. The results of those calculations are shown in Table 7. The data in Table 7 clearly illustrate that the dramatic increase in the prices utilities had to pay for the fuel, natural gas. Over the course of the year, utility natural gas prices rose nearly seven-fold. The Table also highlights the fact that residential electricity rates were relatively stable even in the face of rising input costs. Finally, the high number of heating and cooling degree days shown in the Table are proof that the year 2000 was marked by extended, record hot and cold spells.

Next, I calculated the logs of each of the variables except degree days and time. I, then, calculated the equilibrium price by (1) plugging the coefficients derived in the previous chapter into the supply and demand equations; (2) setting those equations equal to each other; and (3) solving for price. After this, I used the supply (or demand) equation, the data sets and the equilibrium price calculated above to calculate the equilibrium quantity. I also calculated what people would have liked to have consumed at the capped price by plugging the capped prices into the demand equation. The results

[32] See J. Alan Beamon and Steven H. Wade. "Energy Equipment Choices: Fuel Costs and Other Determinants", Monthly Energy Review, April, 1996.

of these calculations are in Table 8. I then calculated the shortages that existed in each month, i.e., the differences between the amounts actually supplied and what consumers would have liked to have consumed. Finally, I calculated the mid-point elasticity for each month. The results of both of these calculations are in Table 8.

Section 4.3: Results:

Table 8 clearly demonstrates that, in each month in 2000, the equilibrium quantity demanded and the quantity consumers would have liked to have consumed are substantially greater than the amounts the utilities actually supplied, indicating that there were shortages. Table 8 further shows that the shortages declined significantly in June, July, August and September, the months when demand was at its highest. This may be because it was during these months that SDG&E raised its rates to levels equal to and in one month in excess of the equilibrium prices shown on Table 8. It was also during these months that I calculated that SDG&E had no shortages.

For illustration purposes, I have included in Figures 1 and 2 supply and demand curves which depict the situation in California in June 1995 and June 2000, respectively. I chose June 2000 because this was the month when PG&E was forced to implement rolling blackouts and the ISO issued several notices or appeals for customers to cut back on their consumption. I chose June 1995 for comparison purposes in order to see if the shortages were any different under regulation than under "deregulation" and capped prices.

The supply and demand curves for June 1995 are shown in Figure 1 as S(95) and D(95). The capped price was 10.919 cents/kWh (P0) and the actual quantity supplied at that price (Q0) was 940,594 MWH. [33] The equilibrium price of 12.881 cents/kWh is labeled P* and the equilibrium quantity of 1,667,286 MWH is labeled Q*. The actual

[33] The prices and quantities are shown on the Figures in logs. The log values are: for 2000, ln(actual price = 2.396; ln(equilibrium price)=2.465; ln(quantity supplied at capped price)= 20.938; ln(equilibrium quantity)= 21.479 and ln(desired demand at capped price)=21.493. For 1995, ln(actual price)=2.391; ln(equilibrium price)=2.556; ln(quantity supplied at capped price)=20.662; ln(equilibrium

demand at the capped price (Q1) was 1,799,461 MWH. The difference between Q0 and Q1, 858,868 MWH, is the shortage.

The supply and demand curves for June 2000 are shown in Figure 2 as S(00) and D(00). The actual quantity supplied that month, 1.239 million MWH, at the capped price of 10.976 cents/kWh is labeled Q0 and P0, respectively. The equilibrium price of 11.764 cents/kWh is labeled P* and the equilibrium quantity of 2.129 million MWH is identified as Q*. Finally, actual demand at the capped price of 10.976 cents/kWh is 2.160 million MWH and is shown on the Figure as Q1. The difference between Q0 and Q1, 920,878 MWH, is the shortage. See Table 8 for the shortages in the other months.

It is interesting to note that the June 1995 and June 2000 equilibrium prices are higher than the prices that were actually charged in those years and the equilibrium quantities are higher than the amounts that were actually supplied. It is also interesting to note that the shortage for June 1995 is comparable to the shortage in June 2000. The logical conclusion here is that consumers and suppliers were no better off under “quasi regulation” than they were under “total regulation”; and that the shortages would have been substantially less if regulators had let the market clear.

Conclusion

The analysis clearly shows that the capped prices did not fully recover the cost of providing the service. The analysis also shows that the price that would have allowed the market to clear was much higher than the capped prices and that the quantities that would have been supplied at the market clearing price were much higher than what was actually supplied. This leads me to conclude that, by allowing residential prices to respond to market forces, the regulators might have avoided or at least minimized the shortages that occurred during the summer of 2000.

---

quantity)=21.234; and ln(desired demand) = 21.311.

Tables and Figures

Table 3- Summary Output from Reduced Form Price Regression

Regression Statistics	
Multiple R	0.814035311
R Square	0.662653487
Adjusted R Square	0.659425291
Standard Error	0.125240825
Observations	845

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	25.75777713	3.219722142	205.2705063	1.9629E-191
Residual	836	13.11288094	0.015685264		
Total	844	38.87065808			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-3.176399557	0.781671508	-4.063599	5.28758E-05
Ln(Income / Capita)	0.012592066	0.084775686	0.148533933	0.881957228
Ln(Population)	-0.086196084	0.02626556	-3.2817151	0.001074555
Ln(Households with Central AC)	-0.072649655	0.013920185	-5.2190151	2.27065E-07
Ln(Households with Space Heaters)	0.541968774	0.037209379	14.56538093	5.37959E-43
Degree Days	1.19833E-05	3.90487E-05	0.306880015	0.759011122
Ln (Residential Price of Gas) - cents/KWH	0.565914274	0.049409767	11.45348998	2.57629E-28
Ln (Utility Price of Gas) cents/KWH	-0.149990258	0.025248337	-5.94059949	4.16388E-09

Table 4- Summary Output from Supply Equation Regression

Regression Statistics	
Multiple R	0.6713741
R Square	0.45074319
Adjusted R Square	0.44812768
Standard Error	0.58544356
Observations	845

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	236.2670038	59.066751	172.3348104	9.664E-108
Residual	840	287.9050999	0.34274417		
Total	844	524.1721037			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	156.653859	52.74041908	2.97028088	0.003060005
Ln (Utility Price of Gas) - cents	-47.390232	46.59949933	-1.0169687	0.309461139
Ln(Reduced Form Price)	3.50391109	0.134514843	26.0485089	4.1121E-110
Time	-0.072645	0.026506277	-2.74067168	0.006261542
Lpg*Time	0.02407067	0.023415251	1.02799116	0.304249905

Table 5- Summary Output from Demand Equation Regression

Regression Statistics	
Multiple R	0.986986476
R Square	0.974142304
Adjusted R Square	0.97392605
Standard Error	0.127253325
Observations	845

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	510.6182205	72.94546007	4504.638957	0
Residual	837	13.55388316	0.016193409		
Total	844	524.1721037			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	0.819537136	1.046050038	0.783458827	0.433579352
Ln(Reduced Form Price)	-0.230388459	0.171100347	-1.34651076	0.178502361
Ln(Income / Capita)	0.563632644	0.086143642	6.542939543	1.04983E-10
Ln(Population)	0.503423316	0.033307581	15.11437649	8.16429E-46
Ln(Households with Central AC)	0.301969667	0.016625535	18.16300449	2.09565E-62
Ln(Households with Space Heaters)	0.255375348	0.106814754	2.390824672	0.017030644
Total Degree Days	0.00069739	3.94158E-05	17.69316479	9.38828E-60
Ln (Residential Price of Gas) - cents/K\	-0.019488708	0.112552422	-0.17315228	0.862573596

Table 6 - Year 2000 Data Set

Utility	Month	Quantity (KWH)	Revenue ($)	Average Electricity Price - cents/KWH	Income/ Per Capita	Population	Households with Central AC	Households with Space Heaters	Degree Days	Utility Pirce of Gas	Residential Price of Gas
PGE	1	2,429,637,000	247,822,974	10.200	15,145	12,211,879	1,255,871	374,932	376	2.83	6.32
PGE	2	2,387,153,000	238,715,300	10.000	15,145	12,211,879	1,255,871	374,932	302	3.23	7.01
PGE	3	2,550,526,000	272,906,282	10.700	15,145	12,211,879	1,255,871	374,932	279	3.38	7.07
PGE	4	2,019,849,000	201,984,900	10.000	15,145	12,211,879	1,255,871	374,932	153	3.54	7.2
PGE	5	1,970,637,000	206,916,885	10.500	15,145	12,211,879	1,255,871	374,932	179	4.19	7.78
PGE	6	2,599,146,000	275,509,476	10.600	15,145	12,211,879	1,255,871	374,932	245	4.87	8.38
PGE	7	2,442,301,000	261,326,207	10.700	15,145	12,211,879	1,255,871	374,932	204	4.68	8.93
PGE	8	2,889,370,000	312,051,960	10.800	15,145	12,211,879	1,255,871	374,932	252	4.85	8.75
PGE	9	2,459,397,000	263,155,479	10.700	15,145	12,211,879	1,255,871	374,932	192	6.01	8.84
PGE	10	2,235,601,000	239,209,307	10.700	15,145	12,211,879	1,255,871	374,932	161	6.19	9.89
PGE	11	2,132,836,000	223,947,780	10.500	15,145	12,211,879	1,255,871	374,932	408	7.68	9.54
PGE	12	2,636,911,000	263,691,100	10.000	15,145	12,211,879	1,255,871	374,932	418	19.91	10.48
SCE	1	2,158,044,859	248,875,327	11.532	12,800	12,629,564	1,508,945	434,332	241	2.83	6.32
SCE	2	1,922,496,099	221,083,836	11.500	12,800	12,629,564	1,508,945	434,332	238	3.23	7.01
SCE	3	1,949,721,011	224,408,207	11.510	12,800	12,629,564	1,508,945	434,332	219	3.38	7.07
SCE	4	1,761,750,298	198,801,890	11.284	12,800	12,629,564	1,508,945	434,332	144	3.54	7.2
SCE	5	1,814,789,834	204,376,263	11.262	12,800	12,629,564	1,508,945	434,332	157	4.19	7.78
SCE	6	2,200,748,842	252,670,207	11.481	12,800	12,629,564	1,508,945	434,332	259	4.87	8.38
SCE	7	2,452,662,894	278,406,927	11.351	12,800	12,629,564	1,508,945	434,332	309	4.68	8.93
SCE	8	2,787,050,462	319,276,809	11.456	12,800	12,629,564	1,508,945	434,332	383	4.85	8.75
SCE	9	2,593,692,039	295,449,531	11.391	12,800	12,629,564	1,508,945	434,332	256	6.01	8.84
SCE	10	2,186,919,437	247,462,671	11.316	12,800	12,629,564	1,508,945	434,332	92	6.19	9.89
SCE	11	2,022,033,341	230,430,237	11.396	12,800	12,629,564	1,508,945	434,332	237	7.68	9.54
SCE	12	2,162,085,769	242,509,186	11.216	12,800	12,629,564	1,508,945	434,332	168	19.91	10.48
SDGE	1	625,759,183	62,763,782	10.030	13,335	3,011,507	256,125	259,373	226	2.83	6.32
SDGE	2	562,648,875	56,171,073	9.983	13,335	3,011,507	256,125	259,373	185	3.23	7.01
SDGE	3	546,905,884	53,893,885	9.854	13,335	3,011,507	256,125	259,373	213	3.38	7.07
SDGE	4	497,610,466	48,348,120	9.716	13,335	3,011,507	256,125	259,373	94	3.54	7.2
SDGE	5	480,555,137	49,807,400	10.365	13,335	3,011,507	256,125	259,373	45	4.19	7.78

Table 6 – Year 2000 Data Set, Continued

Utility	Month	Quantity (KWH)	Revenue ($)	Average Electricity Price - cents/KWH	Income/ Per Capita	Population	Households with Central AC	Households with Space Heaters	Degree Days	Utility Pirce of Gas	Residential Price of Gas
SDGE	6	519,159,089	67,561,856	13.014	13,335	3,011,507	256,125	259,373	96	4.87	8.38
SDGE	7	582,781,417	111,497,093	19.132	13,335	3,011,507	256,125	259,373	128	4.68	8.93
SDGE	8	563,586,256	130,422,205	23.141	13,335	3,011,507	256,125	259,373	218	4.85	8.75
SDGE	9	553,418,203	83,342,635	15.060	13,335	3,011,507	256,125	259,373	164	6.01	8.84
SDGE	10	504,496,390	57,403,772	11.378	13,335	3,011,507	256,125	259,373	66	6.19	9.89
SDGE	11	500,779,362	57,096,702	11.402	13,335	3,011,507	256,125	259,373	199	7.68	9.54
SDGE	12	576,820,079	79,203,203	13.731	13,335	3,011,507	256,125	259,373	216	19.91	10.48
LADWP	1	535,493,000	54,270,125	10.135	12,955	3,720,059	331,594	232,079	234	2.83	6.32
LADWP	2	561,445,000	57,096,407	10.170	12,955	3,720,059	331,594	232,079	239	3.23	7.01
LADWP	3	570,540,000	57,903,308	10.149	12,955	3,720,059	331,594	232,079	224	3.38	7.07
LADWP	4	500,710,000	49,812,671	9.948	12,955	3,720,059	331,594	232,079	145	3.54	7.2
LADWP	5	455,765,000	45,191,066	9.915	12,955	3,720,059	331,594	232,079	132	4.19	7.78
LADWP	6	521,824,000	51,843,828	9.935	12,955	3,720,059	331,594	232,079	215	4.87	8.38
LADWP	7	562,126,000	56,038,151	9.969	12,955	3,720,059	331,594	232,079	266	4.68	8.93
LADWP	8	656,266,000	65,363,209	9.960	12,955	3,720,059	331,594	232,079	337	4.85	8.75
LADWP	9	652,358,000	65,330,535	10.015	12,955	3,720,059	331,594	232,079	230	6.01	8.84
LADWP	10	619,396,000	61,801,545	9.978	12,955	3,720,059	331,594	232,079	62	6.19	9.89
LADWP	11	526,853,000	52,992,047	10.058	12,955	3,720,059	331,594	232,079	218	7.68	9.54
LADWP	12	561,348,000	56,411,939	10.049	12,955	3,720,059	331,594	232,079	207	19.91	10.48
SMUD	1	397,956,655	32,509,772	8.169	12,940	1,219,318	314,291	115,012	504	2.83	6.32
SMUD	2	344,288,775	27,153,703	7.887	12,940	1,219,318	314,291	115,012	394	3.23	7.01
SMUD	3	318,813,253	24,785,505	7.774	12,940	1,219,318	314,291	115,012	301	3.38	7.07
SMUD	4	263,191,932	19,920,710	7.569	12,940	1,219,318	314,291	115,012	158	3.54	7.2
SMUD	5	266,589,767	21,677,510	8.131	12,940	1,219,318	314,291	115,012	192	4.19	7.78
SMUD	6	355,493,613	32,509,536	9.145	12,940	1,219,318	314,291	115,012	251	4.87	8.38
SMUD	7	398,003,673	37,261,882	9.362	12,940	1,219,318	314,291	115,012	220	4.68	8.93
SMUD	8	421,232,958	40,021,452	9.501	12,940	1,219,318	314,291	115,012	288	4.85	8.75
SMUD	9	360,114,644	33,014,659	9.168	12,940	1,219,318	314,291	115,012	198	6.01	8.84
SMUD	10	334,801,574	30,149,289	9.005	12,940	1,219,318	314,291	115,012	161	6.19	9.89
SMUD	11	284,976,750	23,961,797	8.408	12,940	1,219,318	314,291	115,012	492	7.68	9.54
SMUD	12	365,351,862	29,515,917	8.079	12,940	1,219,318	314,291	115,012	560	19.91	10.48

Table 7 – Year 2000 System Average Data

Month	Quantity (KWH)	Revenue ($)	Average Electricity Price - cents/KWH	Income/ Per Capita	Population	Number of Households	Households with Central AC	Households with Space Heaters	Heating Degree Days	Cooling Degree Days	Utility Price of Gas	Residential Price of Gas
1	1,229,378,139	129,248,396	10.513	13,435	6,558,465	2,210,897	733,365	283,146	313	3	2.83	6.32
2	1,155,606,350	120,044,064	10.388	13,435	6,558,465	2,210,897	733,365	283,146	270	1	3.23	7.01
3	1,187,301,230	126,779,437	10.678	13,435	6,558,465	2,210,897	733,365	283,146	245	2	3.38	7.07
4	1,008,622,339	103,773,658	10.289	13,435	6,558,465	2,210,897	733,365	283,146	115	24	3.54	7.2
5	997,667,348	105,593,825	10.584	13,435	6,558,465	2,210,897	733,365	283,146	55	86	4.19	7.78
6	1,239,274,309	136,018,981	10.976	13,435	6,558,465	2,210,897	733,365	283,146	11	202	4.87	8.38
7	1,287,574,997	148,906,052	11.565	13,435	6,558,465	2,210,897	733,365	283,146	9	216	4.68	8.93
8	1,463,501,135	173,427,127	11.850	13,435	6,558,465	2,210,897	733,365	283,146	7	289	4.85	8.75
9	1,323,795,977	148,058,568	11.184	13,435	6,558,465	2,210,897	733,365	283,146	6	202	6.01	8.84
10	1,176,242,880	127,205,317	10.815	13,435	6,558,465	2,210,897	733,365	283,146	77	31	6.19	9.89
11	1,093,495,691	117,685,713	10.762	13,435	6,558,465	2,210,897	733,365	283,146	311	0	7.68	9.54
12	1,260,503,342	134,266,269	10.652	13,435	6,558,465	2,210,897	733,365	283,146	313	0	19.91	10.48
Jun-95	940,593,680	112,256,073	10.919	11,209	6,135,655	2,102,299	659,916	271,237	44.202	98.953	2.560	7.110

Table 8 – Calculation of the Shortage

	Capped Price	Equilibrium Price	Quantity Supplied at Capped Price (Q0)	Equilibrium Quantity (Q*)	Shortage (Q0-Q1) Month - Year	Actual Demand at the Capped Price (Q1) Capped Price	Price Required to Supply Demand at Capped Price	Point Elasticity
Jan-00	10.513	13.775	1,229,378	2,217,302			14.051	0.4913
Feb-00	10.388	13.198	1,155,606	2,166,413	-1,133,290	2,288,897	13.566	0.4148
Mar-00	10.678	12.983	1,187,301	2,137,697	-1,048,056	2,235,357	13.403	0.3615
Apr-00	10.289	12.541	1,008,622	1,997,368	-1,078,783	2,087,406	13.239	0.3222
May-00	10.584	12.029	997,667	2,016,580	-1,076,236	2,073,903	12.659	0.2059
Jun-00	10.976	11.764	1,239,274	2,128,523	-920,878	2,160,152	12.163	0.1413
Jul-00	11.565	11.907	1,287,575	2,137,985	-865,674	2,153,249	12.292	0.0633
Aug-00	11.850	11.982	1,463,501	2,243,066	-784,854	2,248,355	12.176	0.0282
Sep-00	11.184	11.153	1,323,796	2,145,120	-815,251	2,139,047	11.501	-0.0064
Oct-00	10.815	10.832	1,176,243	2,010,117	-836,016	2,012,259	11.411	0.0033
Nov-00	10.762	10.725	1,093,496	2,321,801	-1,222,189	2,315,685	10.775	-0.0055
Dec-00	10.652	8.475	1,260,503	2,451,786	-1,083,167	2,343,670	8.364	-0.4080
Jun-95	10.919	12.881	940,594	1,667,286	-858,868	1,799,461	14.431	0.3146

Figure 1 - 1995 Shortage

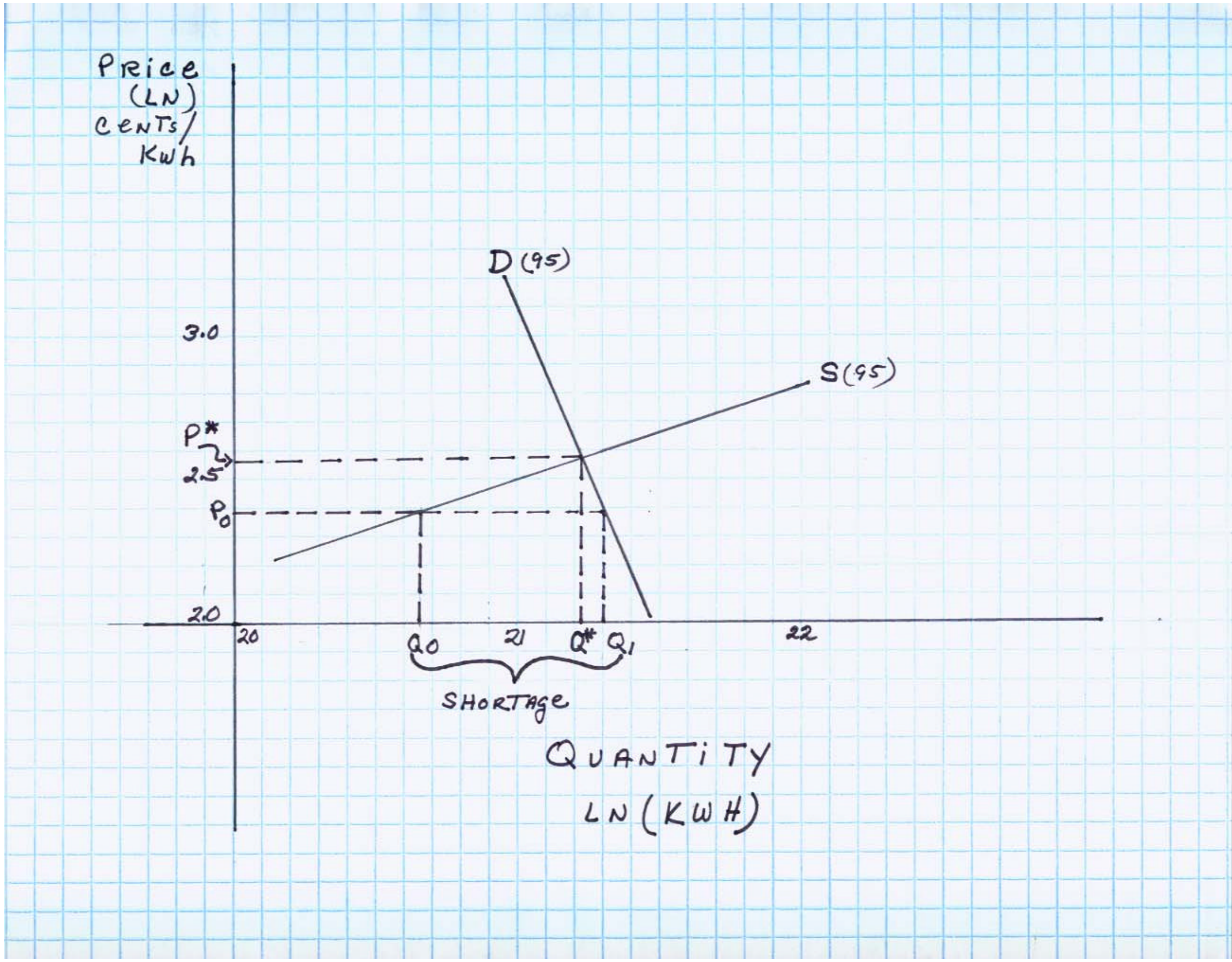
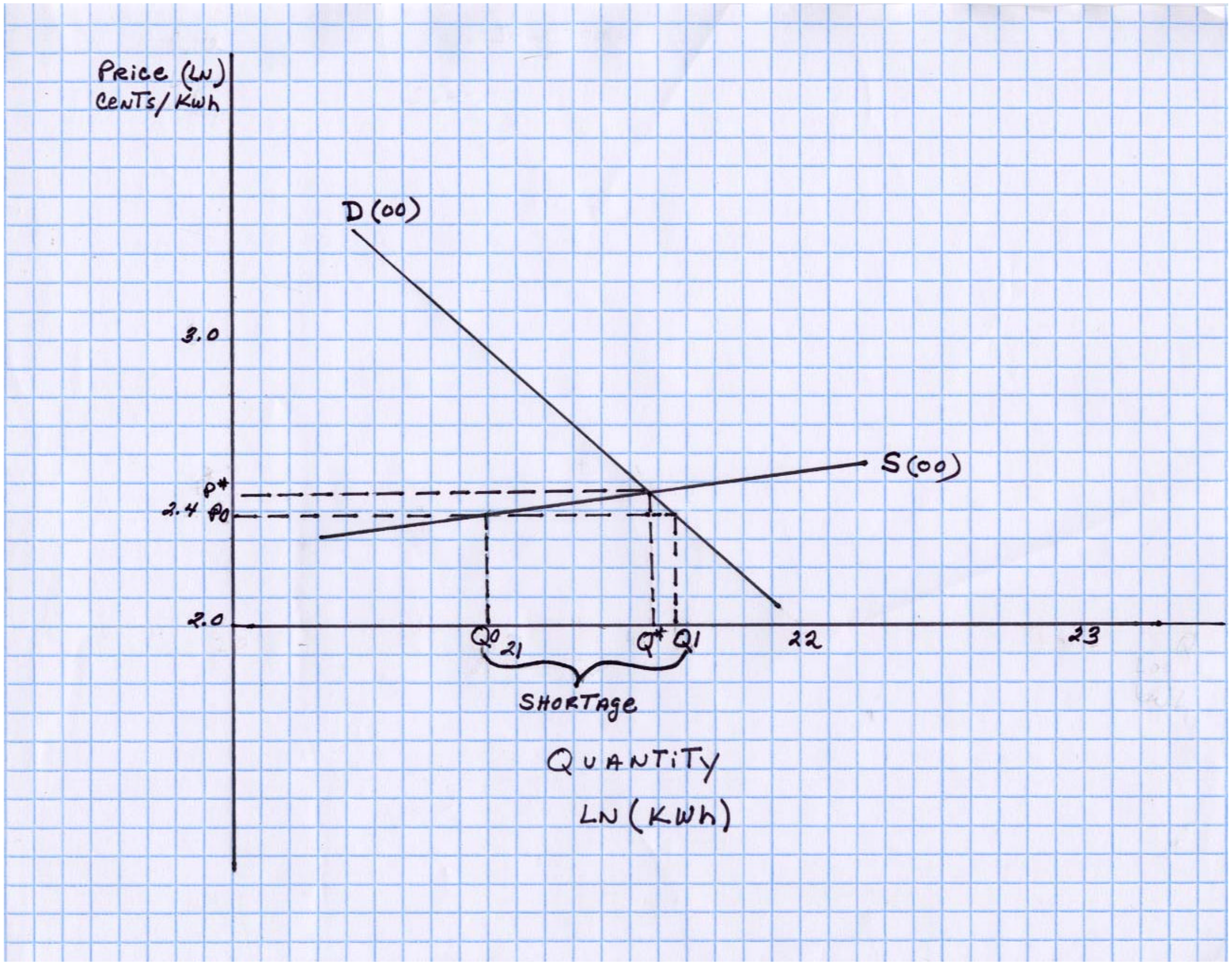


Figure 2 – 2000 Shortage



References

Author unknown. “California’s Power Crisis”, The Economist. January 20, 2001.

Bohi, Douglas R. Analyzing Demand Behavior – A Study of Energy Elasticities. Johns Hopkins University Press. 1981.

Borenstein, Severin; Bushnell, James; Wolak, Frank. Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market. Working Paper Series of the Program on Workable Energy Regulation (POWER). University of California, Berkeley. August 2000.

California Energy Commission. 1994 Electricity Report, Publication Number P300-95-002. November 1995.

California Energy Commission. 1996 Electricity Report.

California Energy Commission. What Electricity Restructuring Means for Rural California Counties, Staff Report. Publication Number 300-98-011.

California Energy Commission. California Energy Outlook – Electricity and Natural Gas Trends Report. Staff Draft. September 2001.

California ISO. Annual Report on Market Issues and Performance. Prepared by the Market Surveillance Unit, California Independent System Operator. June 1999.

California ISO. Report on California Energy Market Issues and Performance: May-June 2000 Special Report. Prepared by the Department of Market Analysis, California Independent System Operator. August 10, 2000.

California ISO. 2002 Summer Assessment, Version 1.0. Operations Engineering, California ISO. April 25, 2002.

California Power Exchange Corporation, Compliance Unit. Price Movements in California Electricity Markets: Analysis of May-July 2000 Price Activity. September 29, 2000.

Chang, Hui S. and Chern, Wen S. The Demand for Residential Electricity: New Evidence on the Varying Elasticities. Applied Economics, 1991, 23, 1251-1256.

Cowing, Thomas G. and McFadden, Daniel L. Economic Theory, Econometrics and Mathematical Economics, "Microeconomic Modeling and Policy Analysis – Studies in Residential Energy Demand". Academic Press, Inc., 1994.

Energy Information Agency, Department of Energy. Residential Sector Demand Module of the National Energy System. DOE/EIA-MO67 (2000). December 1999.

Energy Information Agency, Department of Energy. Short-Term Energy Outlook Electricity Model Description.

Federal Energy Regulatory Commission. Order Proposing Remedies for California Wholesale Electric Markets. Issued November 1, 2000.

Federal Energy Regulatory Commission. Staff Report on Western Markets and the Causes of the Summer 2000 Price Abnormalities. Part 1, Staff Report on U.S. Bulk Power Markets, November 1, 2000.

Greene, William. Econometric Analysis. Fourth Edition. Prentice Hall. 2000.

Halvorsen, Robert. Econometric Models of U.S. Energy Demand. Lexington Books. 1978.

Kahn, Michael, Chairman, Electricity Oversight Board and Lynch, Loretta, President, California Public Utilities Commission. California's Electricity Options and Challenges - Report to Governor Gray Davis. Friday, May 24, 2002.

Levine, David; Stephan, David; Krehbiel, Timothy; and Berenson, Mark. Statistics for Managers Using Microsoft Excel. Third Edition. Prentice Hall. 2002.

Joskow, Paul and Kahn, Edward. A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000. November 21, 2000.

Econometric Studies in Energy Demand. Edited by Maddala, G. S.; Chern, Wen S.; and Gurmukh, Gill S. Praeger Publishers. 1978.

Pindyck, Robert S. and Rubinfeld, Daniel L. Econometric Models and Economic Forecasts. Fourth Edition. Irwin McGraw-Hill. 1998.

Taylor, Jerry and VanDoran, Peter. "California's Electricity Crisis What's going On, Who's to Blame and What to Do". Policy Analysis, No. 406. July 3, 2001.

Wolak, Frank; Nordhaus, Robert; and Shapiro, Carl. Market Surveillance Committee of the California Independent System Operator. An analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets. September 6, 2000

Biography

Julia Tuzun received her Bachelor of Arts degree in Economics from Marygrove College in Detroit, Michigan. Since graduating from Marygrove, Ms. Tuzun has worked for the United States Senate, the Institute for Policy Studies, the International Bank for Reconstruction and Development (the World Bank), and the Middle East Technical University in Ankara, Turkey. She is currently employed as an Energy Industry Analyst at the Federal Energy Regulatory Commission in Washington, D.C.