HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EMPIRICAL EVIDENCE

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HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EMPIRICAL EVIDENCE

Since the energy crisis of 2000-2001 in the western United States, much attention has been given to boosting demand response in electricity markets. One of the best ways to let that happen is to pass through wholesale energy costs to retail customers. This can be accomplished by letting retail prices vary dynamically, either entirely or partly. For the overwhelming majority of customers, that requires a changeout of the metering infrastructure, which may cost as much as $40 billion for the US as a whole. While a good portion of this investment can be covered by savings in distribution system costs, about 40 percent may remain uncovered. This investment gap could be covered by reductions in power generation costs that could be brought about through demand response. Thus, state regulators in many states are investigating whether customers will respond to the higher prices by lowering demand and if so, by how much.

To help inform this assessment, we survey the evidence from the 15 most recent pilots, experiments and full-scale implementations of dynamic pricing of electricity. We find conclusive evidence that households (residential customers) respond to higher prices by lowering usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. They also vary with the design of the studies, the tools used to analyze the data and the geography of the assessment. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs induce a drop in peak demand that ranges between 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range.

1.0 INTRODUCTION

Electricity cannot be stored economically in large quantities, and has to be consumed instantly on demand. The load duration curve for most utility systems is very peaky, with some 8 to 10 percent of annual peak load concentrated in the top one percent of the hours of the year. These two factors, taken in conjunction with the variation in marginal energy and capacity costs that characterizes different generation technologies, mean that the optimal way for pricing electricity would be for regulators to institute time-varying rates for generation service provided either by vertically-integrated utilities in non-restructured states or by distribution-only utilities that provide standard offer service in restructured states..[2] Nevertheless, for the past century, electricity pricing has violated this optimality condition and been based on average cost. This

[2] For a survey, see Crew, Fernando and Kleindorfer (1995). A case for dynamic as opposed to static time-varying rates was provided by Vickrey (1971). Chao (1983) introduced uncertainty into the analysis. Littlechild (2003) made a case for passing through wholesale costs to retail customers. Borenstein (2005) compared the efficiency gains of dynamic and static time-varying rates.

has had the unfortunate effect of encouraging excessive consumption of electricity during the expensive peak-period hours and discouraging consumption during the inexpensive off-peak period hours. Over time, as the penetration of central air conditioning systems has deepened in most parts of the country, load factors have deteriorated and the peak loads have become more pronounced. To eliminate the deadweight loss associated with average-cost pricing, prices during the off-peak period should be set equal to the marginal cost of energy and prices during the peak period should be set equal to the marginal cost of energy and capacity. There is widespread consensus in the economics literature that such a shift in the pricing paradigm would increase both consumer surplus and producer surplus and raise societal welfare by lowering the average cost of electricity. Such a change would also pass most the "standard practice" tests that are used by state commissions to evaluate demand-side programs.[3]

So why has practice lagged theory, creating one of the longest-lasting paradoxes in the field of public utility regulation? There are several reasons, with the foremost being the cost of installing the advanced metering infrastructure (AMI) that would allow dynamic pricing to be implemented. As shown later in the paper, this is an expensive proposition which may amount to $40 billion for the nation as a whole. .

But an equally important reason is political, which stems from the fear held by state regulators and utility alike of a consumer backlash from time-varying rates.[4] Undoubtedly, prices would rise during the peak period but, consistent with standard regulatory practice; lower off-peak prices would be implemented concomitantly so that, on average, customer bills will not change. In fact, half of the customers who have higher load factors than the class profile would see lower bills. But the other half with poorer-than-average load factors would be instant losers (unless they curtailed peak usage) and may revolt. The dread of such a prospect has stymied innovation in rate design. Needless to say, if the price change being envisioned is not just a move to time-of-use (TOU) pricing but a move to dynamic pricing, which is likely to maximize the social surplus, then concerns about price volatility further muddy the waters.

However, there are signs of change in the policy-setting environment. These changes are visible both in restructured states where the utility provides standard offer generation services but

[3] Earle and Faruqui (2006).

[4] Faruqui (2007) and Wolak (2007).

customers are free to shop-around for competitive retailers and in fully-regulated states where the utility is the only provider of generation services. In most restructured states, the utility remains the dominant supplier, often accounting for all but a few percent of the residential customers.

It is now widely recognized in the regulatory community at both the state and federal levels that the energy crisis in the Western US that occurred during the years 2000-01 was caused in part by a failure to engage the demand side of the California power market. When prices skyrocketed in wholesale markets, retail customers had no incentive to reduce demand. Governor Gray Davis famously observed that he could have solved the crisis in 20 minutes had he been able to pass through the rising prices to customers. By freezing retail prices, Davis rendered inoperative the automatic stabilizer that could have brought demand and supply back into balance.[5]

After the crisis, twenty one economists put forward a manifesto which argued:[6]

> Any structural model for the industry should include a mechanism for charging consumers for the cost of the production and delivery of electricity at the time of its consumption. Electricity at midnight in April is completely different from electricity at noon on a hot August day. …Prices to most end users don't signal when electricity is cheap or dear for the industry to produce. Nor are consumers offered the true economic benefit of their conservation efforts at times of peak demand. Customers suffer further when unchecked peak demands grow too fast, pushing up costs for all. Wholesale electricity markets also become more volatile and subject to manipulation when rising prices have no impact on demand. Indeed, a functioning demand side to the electricity market in California would have greatly reduced the likely private benefits, and consequent social cost, of any strategic behavior engaged in during the crisis…Regardless of other reform efforts that are pursued in California, real-time pricing or other forms of flexible pricing is a key to enhanced conservation, more efficient use of electricity, and the avoidance of both unnecessary new power plants as well as concerns about the competitiveness of wholesale electricity markets.

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5 Borenstein (2002) and Faruqui, Chao, Niemeyer, Platt and Stahlkopf (2001a) and (2001b).

6 Bandt, Campbell, Danner, Demsetz, Faruqui, Kleindorfer, Lawrence, Levine, McLeod, Michaels, Oren, Ratliff, Riley, Rumelt, Smith, Spiller, Sweeney, Teece, Verleger, Wilk and Williamson (2003).

The manifesto left two questions unanswered. First, whether or not customers would respond to higher prices by reducing demand.[7] And second, whether it would make economic sense to equip ten million residential and small commercial and industrial customers with the AMI that would be necessary to transmit such dynamic price signals to them.[8] To answer these questions, the California Public Utilities Commission (CPUC) initiated a proceeding on advanced metering, demand response and dynamic pricing.[9]

As part of the proceeding, the state carried out one of the most comprehensive experiments with dynamic pricing. It showed conclusively that residential customers responded to prices that were five times higher than the standard tariff during the top 75 hours of the year by lowering usage by 13 percent.[10] The three investor-owned utilities in the state relied on the results from the experiment to develop their AMI business cases. They showed that while AMI yielded many operational benefits to the distribution system, such benefits only covered about sixty percent of the total investment. The remaining forty percent had to be covered through demand response.

The CPUC has approved all three business cases. Over the next five years, California will deploy 11.8 million smart meters for electricity (and about five million for gas) for a total investment of $4.564 billion.[11] Capitalizing on this transformation of the metering landscape, the CPUC issued a decision this past summer that calls for placing all customers who have advanced meters on critical-peak pricing.[12] If dynamic pricing becomes the default tariff, substantial benefits can accrue to customers. If it is offered only as an optional tariff, benefits would be about a quarter to a tenth as large.[13]

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7 This question was answered at least temporarily in San Diego where wholesale prices were allowed to flow through to retail customers in the summer of 2000. When prices doubled, customers lowered their usage by 13 percent. See Reiss and White (2008).

8 The question of whether meter changeout is cost-effective does not arise for large commercial and industrial customers since such a changeout is prima facie cost-effective. In addition, there is substantial evidence on the price responsiveness of such customers. See, for example, Taylor, Schwarz and Cochell (2005) and the case studies in Faruqui and Eakin (2000) and (2002).

9 CPUC R. 02-06-001. http://docs.cpuc.ca.gov/published/proceedings/R0206001.htm.

10 Faruqui and George (2005), Herter (2007), and Herter, McAuliffe and Rosenfeld (2007).

11 California Energy Commission (2008). In addition to the electric meters, about 5 million gas meters are also being upgraded.

12 CPUC, Decision adopting dynamic pricing timetable and rate design guidance for Pacific Gas & Electric Company, D. 08-07-045, July 31, 2008.

13 Pfannenstiel and Faruqui (2008).

Similar discussions are taking place in many jurisdictions throughout North America, spurred in part by two federal laws.[14] As noted earlier, both restructured and traditionally regulated states are simultaneously engaged in this re-examination of metering and demand response issues. A survey of state regulatory activity carried out in August 2008 found that 38 commissions had initiated regulatory consideration of smart meters and demand response in response to federal legislation and 32 had completed their consideration.[15]

Echoing views that were espoused in the 21 Economists Manifesto, Frederick Butler of the New Jersey Board of Public Utilities Commission, who is also the president of the National Association of Regulatory Utility Commissioners, reminded EnergyWashington in December 2008 that for more than a century "most people have paid for their electricity at the same rate every day of every year, every hour of every day." Butler said, "That's going to have to change," noting that "If you're going to have a smart grid, that allows you to measure and have two-way communication between the end-use premises, the utility company, the [Regional Transmission Operator] RTO, and other entities, rates will have to change to be more time-of-use rates or critical peak period rates."

The momentum toward dynamic pricing and demand response has also extended to wholesale markets. Many regional transmission organizations and independent system operators around the US including those in California, the Midwest, New England, New York and PJM are giving serious consideration to introducing demand response in wholesale markets. A recent analysis showed that even a five percent reduction in US demand during the top one percent of the hours of the years would yield a present value of $35 billion in benefits.[16]

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14 The Energy Policy Act of 2005 and The Energy Independence and Security Act of 2007 ask state commissions to consider the deployment of smart meters and demand response. The latter act also asks the Federal Energy Regulatory Commission to carry out a state-by-state assessment of the potential for demand response.

15 US Demand Response Coordinating Committee, (2008).

16 Faruqui, Hledik, Newell and Pfeiffenberger (2007). With updated assumptions about the cost of peaking capacity, the benefit estimate might be closer to $66 billion.

To effectuate demand response, some type of dynamic pricing will have to be instituted in retail markets.[17] The central question in all of these assessments is: Will customers respond to higher prices by lowering peak demand and if so, by how much? The answer will help state regulators determine whether or not to proceed with authorizing the deployment of AMI in their jurisdictions. The question applies a fortiori to residential and small commercial and industrial customers because only five percent are equipped with smart meters.[18] In the U.S., there are a total of 144 million customers. Of this number, the overwhelming majority –some 125 million— are residential.[19] They account for a third of over-all energy consumption and for a larger share of peak demand.

The cost of upgrading all residential meters in the US would be staggering. Using the California cost of AMI deployment as a proxy variable, we estimate that the nationwide cost of AMI would be upwards of $40 billion. Is it worthwhile to pursue AMI? The answer is a conditional yes. Two things have to occur to make this a sound decision. First, AMI should be accompanied by dynamic pricing to get the most value out of the investment. As Commissioner Rick Morgan of the District of Columbia Public Service Commission has noted, what is the point of getting smart meters with dumb rates?[20] This represents a major change in the pricing paradigm and will be actively debated by commissions in every state before a consensus is arrived at. Second, customer response to dynamic pricing has to create savings in avoided capacity and energy costs to overcome the net investment in AMI (i.e., that amount which is not offset by savings in distribution system costs). The second condition is largely an empirical issue and provides the impetus for this paper.

In Section 2, we provide an overview of 15 recent empirical assessments of dynamic pricing. Several were conducted as scientifically designed experiments with balanced control and treatment groups, a few were designed with treatment groups that were not randomly chosen and some are full-scale deployments with no experimental controls. We tabulate the design characteristics of these 15 assessments and summarize the analytical process through which the data are analyzed. In Section 3, we review in detail the design of each individual assessment and

17 Wellinghoff and Morenoff (2007).
18 FERC (2008).
19 http://www.eia.doe.gov/cneaf/electricity/esr/table5.html.
20 Morgan (2009).

present its results. In Section 4, we compare the results across experiments and also illustrate the likely effect of dynamic pricing on customer peak loads by relying on the results of one of the most widely-cited pricing experiments. In Section 5, we present our conclusions.

2.0 THE FIFTEEN EXPERIMENTS

In the late 1970s and early 1980s, the first wave of electricity pricing experiments was carried out under the auspices of the US Federal Energy Administration. Those experiments were focused on measuring customer response to simple (static) time-of-day and seasonal rates.[21] There was a lot of variation in the experimental results, with the own-price elasticity of peak period consumption ranging between 0 and -0.4. A similar variation was observed for the own-price elasticity of off-peak consumption. Cross-price elasticities tended to be much smaller. Some of the variation in results was caused by differences in customer demographics and weather conditions. Some of the residual variation was undoubtedly caused by variations in experimental design and the levels of prices that were offered in the experiments. The data from the top five experiments, located in California, Connecticut, North Carolina and Wisconsin, were analyzed in a major study carried out for the Electric Power Research Institute (EPRI).[22]

The constant elasticity of substitution (CES) model was used in the EPRI study. This model merits some discussion since it has also been used in several subsequent studies. Data in electricity pricing studies that involve individual customers, whether experimental or otherwise, is limited to repeated observations of electricity consumption and prices by period. Thus, if the analyst wishes to estimate demand functions that are consistent with the theory of utility maximization, he or she is forced to assume a two-stage budgeting process on the consumer's part. Often, this means invoking the assumption of homothetic separability in consumer preferences which posits inter alia that the ratio of peak to off-peak consumption does not depend on the amount being spent on electricity. The CES model allows the elasticity of substitution to take on any value and it has been found to be well-suited to TOU pricing studies involving electricity since there is strong prior evidence suggesting that these elasticities are going to be small.

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[21] Faruqui and Malko (1983).
[22] Caves, Christensen, and Herriges (1984).

The CES model is superior to the Cobb-Douglas model which imposes a unitary elasticity of substitution. The Cobb-Douglas model is estimated, for example, by regressing the log of peak-period consumption on the log of peak and off-peak prices. To be consistent with theory of utility maximization, cross-equation restrictions have to be imposed on the cross-price terms. In addition, the model forces the underlying elasticity of substitution to be one, which has not been observed empirically. Often, the cross-equation restrictions are not imposed, the equations are estimated by ordinary least squares (OLS) and the result is an unappealing ad hoc specification.

The CES model is estimated by regressing the ratio of peak consumption to off-peak consumption on the corresponding price ratio. Often, daily observations are used in the regressions. Thus it becomes to introduce weather terms in the specification. Finally, it is customary to introduce fixed effects in the specification, allowing each customer to have their unique intercept terms that reflect their lifestyles. A separate equation is used to model changes in daily use (the sum of peak and off-peak period use) on daily price. To improve the efficiency of the estimators, the substitution and daily equations can be estimated jointly using Zellner's seemingly unrelated estimation procedure.

In order to apply the CES specification across the five experiments, the analysts had to account for the fact that each experiment had its own unique weather conditions and unique consumer appliance holdings. Thus, in the final specification, the elasticity of substitution was allowed to vary with both weather conditions and appliance holdings. The results were conclusive: customers responded to higher prices during the peak period by reducing peak period usage and/or shifting it to less expensive off-peak periods. The results were consistent around the country once weather conditions and appliance holdings were held constant. Customer response was higher in warmer climates and for customers with all electric homes. The elasticity of substitution for the average customer was 0.14, indicating that a one percent rise in the ratio of peak-to-off peak prices would result in a 0.14 percent drop in the peak-to-off-peak quantity ratio. Over the entire set of customers, it ranged between 0.07 and 0.21. The bottom end of the range was found in mild climate regions and was associated with customers that had few electric appliances. The top end of the range was found in extreme climate regions and was associated with customers that had all-electric homes.

However, despite the conclusive findings from the EPRI study, time-varying rates were not widely accepted across the country. There were three reasons for this. First, the high cost of time-of-use metering. Second, the peak periods in the TOU rate designs were too broad to garner customer acceptance. And third, for reasons that are not entirely clear, the utilities failed to market the programs effectively. Most customers did not even know such rates existed.

California's energy crisis rekindled interest in time-varying rates but with a noticeable difference. A variety of academics, researchers and consultants called for the institution of rates that would be dynamically dispatchable during critical-price periods. These occur typically during the top one percent of the hours of the year where, as noted earlier, somewhere between 9-17 percent of the annual peak demand is concentrated. It is very expensive to serve power during these critical periods and even a modest reduction in demand can be very cost-effective. In addition, the introduction of digital technology in meters has brought with it the availability of AMI, making dynamic pricing a cost-effective option in most situations.

The study designs are shown in Table 1. Most of them are based on panel data, involving repeated measurements on a cross-section of customers. Some of the customers are placed on the dynamic pricing rate (or rates) and fall into the treatment group. Others stay on existing rates and fall into the control group. To be a true experiment, the treatment and control groups should be randomly chosen. Otherwise, the design becomes a quasi experiment.[23] The better designs feature measurement during the pre-treatment period which allows any potential self-selection bias in the treatment group to be detected. It also allows for the application of the "difference-in-differences" estimator, obtained by subtracting (any) pre-existing difference in the usage of the control group between treatment and pre-treatment periods from that of the treatment group between the treatment and pre-treatment periods. Finally, the superior designs feature multiple price points, allowing for the estimation of demand models and price and substitution elasticities which can be used to predict not only the impact of the specific rates tested in the study but also

[23] Shadish, Cook and Campbell (2002).

other rates. The simpler designs had a single time-varying rate and only allowed a comparison of means to be carried out using either analysis of variance (ANOVA) or covariance (ANCOVA). The results in such cases are limited to the time-varying rates tested in the study and cannot be used to assess alternative values of peak and off-peak prices.

As mentioned earlier, one of the more popular and theoretically appealing model specifications is the constant elasticity of substitution (CES) demand system. Its application to electricity pricing centers on the substitution equation (1). The equation expresses the peak to off-peak quantity ratio as a function of the peak to off-peak price ratio[24], a weather term representing the difference in cooling degree hours between the peak and off peak periods[25] and fixed effects variable for each customer.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta\,(CDH_p - CDH_{op}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon$$

where

Q_p = average energy use per hour in the peak period for the average day

Q_{op} = average energy use per hour in the off-peak period for the average day

σ = the elasticity of substitution between peak and off-peak energy use (following convention, this is taken to be a positive number for substitutes and a negative number for complements)

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = cooling degree hours per hour during the peak pricing period

CDH_{op} = cooling degree hours per hour during the off-peak pricing period

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24 It is important to note that this specification can be estimated without any concerns about simultaneous equation bias since prices are set ex ante in just about all of the experiments reviewed in the paper and in a few of the full-scale deployments noted below, the number of participants was not large enough to create demand response of such magnitude that it would influence prices in retail markets.

25 The difference in cooling degree hours per hour between peak and off-peak periods is used rather than the ratio because on some days, there are zero cooling degree hours in the off-peak period and using the ratio would result in division by zero on these days.

θ_i = fixed effect coefficient for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = random error term

Equation (2) expresses daily energy use as a function of daily average price, daily cooling degree hours and the fixed effects variables.

$$\ln(Q_d) = \alpha + \eta_d \ln(P_d) + \delta(CDH_d) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon$$

where

Q_d = average daily energy use per hour

η_d = the price elasticity of demand for daily energy (defined below)

P_d = average daily price (e.g., a usage weighted average of the peak and off-peak prices for the day)

CDH_d = cooling degree hours per hour during the day

ε = regression error term

The two summary measures of price responsiveness in the CES demand system are the elasticity of substitution (σ) and the daily price elasticity of consumption (η).

It is plausible that the elasticity of substitution and/or the daily price elasticity would differ across customers who have different socio-economic characteristics (e.g., different appliance ownership, different income levels, etc.). The elasticity may also vary between hot and cool days. The CES model can be modified to allow the elasticities to vary with weather and socio-economic factors, such as central air conditioning (CAC) ownership. Equation (3) provides an example of the substitution equation that allows price responsiveness to vary with CAC ownership and weather. Equation (4) shows how the elasticity of substitution would be calculated from this model specification. Equations (5) and (6) show the demand models for daily energy use and the corresponding equation for the daily price elasticity as a function of weather and CAC ownership.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op})\ln\left(\frac{P_p}{P_{op}}\right)$$
$$+ \varphi(CAC)\ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon$$

The elasticity of substitution (ES) in this model is a function of three terms, as shown below:

$$\text{ES}=\sigma + \lambda(CDH_p - CDH_{op}) + \varphi(CAC)$$

Other customer characteristics, such as income, household size, and number of people in the household, may also influence the elasticities in the CES model. They can be included in the specification by introducing additional price interaction terms in a similar manner to the CAC and weather terms shown above.

$$\ln(Q_D) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \eta\ln(P_D) + \rho(CDH_D) + \chi(CDH_D)\ln(P_D) + \xi(CAC)\ln(P_D) + \varepsilon \qquad (5)$$

where

Q_D = average daily energy use per hour

η = the daily price elasticity

P_D = average daily price

ρ = measure of weather sensitivity

χ = the change in daily price elasticity due to weather sensitivity

CDH_D = average daily cooling degree hours per hour (base 72 degrees)

ξ = the change in daily price elasticity due to the presence of central air conditioning

CAC = 1 if a household owns a central air conditioner, 0 otherwise

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = error term.

The composite daily price elasticity in this model is a function of three terms, as shown below:

$$\text{Daily} = \eta + \chi(CDH_D) + \xi(CAC) \qquad (6)$$

Table 1- Overview of the studies

No	State/ Province	Experiment	Utility	Year	Number of Customers	Number of Rates Tested	Link to Figure 1
1	California	Anaheim Critical Peak Pricing Experiment	Anaheim Public Utilities (APU)	2005	52 control, 71 treatment	1	Anaheim
2	California	California Automated Demand Response System Pilot (ADRS)	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2004-2005	In 2004: 104 control, 122 treatment In 2005: 101 control, 98 treatment	1	ADRS-04, ADRS-05
3	California	California Statewide Pricing Pilot (SPP)	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2003-2004	2,500 customers	3	SPP, SPP-A, SPP-C
4	Colorado	Xcel Experimental Residential Price Response Pilot Program	Xcel Energy	2006-2007	1350 control, 2349 treatment	3	XCEL-TOU, XCEL-CPP, XCEL-CTOU
5	Florida	The Gulf Power Select Program	Gulf Power	2000-2001	2300 customers participating in the RSVP program	2	GulfPower-1, GulfPower-2
6	France	Electricite de France (EDF) Tempo Program	Electricite de France (EDF)	Since 1996	400,000 customers	1	-
7	Idaho	Idaho Residential Pilot Program	Idaho Power Company	2005-2006	TOD Program- 420 control, 85 treatment EW Program- 355 control, 68 treatment	2	Idaho
8	Illinois	The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)	Commonwealth Edison	2003-2005	1,500 customers	2	ESPP
9	Missouri	AmerenUE Residential TOU Pilot Study	AmerenUE	2004-2005	TOU - 89 control, 88 treatment TOU/CPP- 89 control , 85 treatment TOU/CPP w/ Technology- 117 control, 77 treatment	2	Ameren-04, Ameren-05
10	New Jersey	GPU Pilot	GPU	1997	Not Available	2	GPU
11	New Jersey	Public Service Electric and Gas (PSE&G) Residential Pilot Program	Public Service Electric and Gas Company (PSE&G)	2006-2007	450 control, 836 treatment	1	PSE&G
12	New South Wales (Australia)	Energy Australia's Network Tariff Reform	Energy Australia	2005	TOU program: 50,000 customers SPS: 1300 treatment	Tested several dynamic tariffs	Australia
13	Ontario (Canada)	Ontario Energy Board Smart Price Pilot	Hydro Ottawa	2006-2007	125 control, 373 treatment	3	Ontario-1, Ontario-2
14	Washington	Puget Sound Energy (PSE)'s TOU Program	Puget Sound Energy	2001-2002	300,000 customers	1	PSE
15	Washington and Oregon	Olympic Peninsula Project	Bonneville Power Administration, Clallam County PUD, The City of Port Angeles, Portland General Electric, and PacifiCorp	2005	28 control, 84 treatment	3	Olympic P.

3.0 STUDY-BY-STUDY ASSESSMENT

This section profiles the 15 studies by presenting their salient design features, estimated impacts and, wherever they were provided, the price and substitution elasticities. The quality of information varies considerably across the studies and this sometimes gets in the way of providing a consistent perspective.

3.1 California- Anaheim Critical Peak Pricing Experiment

The City of Anaheim Public Utilities (APU) conducted a residential dynamic pricing experiment between June 2005 and October 2005.[26] A total of 123 customers participated in the experiment: 52 in the control group and 71 in the treatment group. Despite its name, this experiment did not feature a critical peak pricing rate. Instead, it provided participants a rebate for each kWh reduction during critical hours. The magnitude of the peak time rebate (PTR) was \$0.35 for each kWh reduction below the reference level peak-period consumption on non-CPP days (i.e., the baseline consumption). The rate design is presented in Table 2.

Table 2- Anaheim PTR Rate Design

Group	Charge	Applicable Period
Control	Standard increasing-block residential tariff: \$0.0675/kWh if consumption <=240kWh per month \$0.1102/kWh if consumption >240kWh per month	All hours
Treatment	Standard increasing-block residential tariff	All hours except except peak hours (12 a.m. - 6 p.m.) on CPP days
Treatment	\$0.35 rebate for each kWh reduction relative to their typical peak consumption on non-CPP days.	Peak hours (12 a.m. - 6 p.m.) on CPP days

Statistical comparisons during the pre-treatment period between treatment and control group customers were not statistically significant indicating that the two groups were balanced and there was no self-selection bias.

The data showed that the treatment group used 12 percent less electricity on average during the peak hours of the CPP days than the control group. Demand response by treatment customers was greater on higher temperature CPP days than on lower temperature CPP days.

[26] Wolak (2006).

3.2 California- Automated Demand Response System Pilot[27]

California's Advanced Demand Response System (ADRS) pilot program was carried out on a subset of the customers who were included in the Statewide Pricing Pilot which is discussed in the next sub-section. All the ADRS participants were located in the upper portion of the Central Valley. The experiment was initiated in 2004 and extended through the end of 2005. ADRS operated under a critical peak pricing tariff that was identical to that in the SPP which was supported with a residential-scale, automated demand response technology. Participants of the pilot installed the GoodWatts system, an advanced home climate control system that allowed users to web-program their preferences for the control of home appliances. Under the CPP tariff, prices were higher during the peak period (2 p.m. to 7 p.m. on weekdays). All other hours, weekends, and holidays were subject to the base rate. When the "super peak events" were called, the peak price was three times higher than the regular peak price.

Program participants achieved substantial load reductions in both 2004 and 2005 compared to the control group. Load reductions on super peak event days were consistently about twice the size of load reductions during the peak periods on non-event days. Peak reductions were as high as 51 percent on event days, when participants faced a critical-peak pricing (CPP) rate and 32 percent on non-event days when participants faced a TOU rate. Enabling technology emerged as the main driver of the load reductions especially on super peak event days and for the high consumption customers. Overall, load reductions of the ADRS participants were consistently larger than those of the other demand response program participants without the technology.

Table 3 presents the impact estimates from the ADRS for high consumption customers on CPP event days and non-event days.

Table 3- Peak Period Load Reductions for High Consumption Customers

[27] Rocky Mountain Institute (2006).

Program Year	Event Days		Non-Event Days	
	Average Reduction (kW)	% Reduction	Average Reduction (kW)	% Reduction
2004	1.84	51%	0.86	32%
2005	1.42	43%	0.73	27%

3.3 California- Statewide Pricing Pilot[28]

California's three investor-owned utilities, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), together with the two regulatory commissions conducted the Statewide Pricing Pilot (SPP) that ran from July 2003 to December 2004 to test the impact of several time-varying rates. The SPP included about 2,500 participants including residential and small-to-medium commercial and industrial (C&I) customers. SPP tested several rate structures. The first one was a TOU-only rate where the peak price was twice the value of the off-peak price. The second one was a CPP rate where the peak price during 15 "critical" days was roughly five times greater than the off-peak price; on non-critical days, a TOU rate applied. The SPP tested two variations of the CPP rates, CPP-F and CPP-V. The CPP-F rate had a fixed period of critical peak and day-ahead notification. CPP-F customers did not have an enabling technology. The CPP-V rate had a variable-length critical peak period and this was activated on a day-of basis. CPP-V customers were provided enabling technologies such as a two-way communicating smart thermostat.

The SPP data were analyzed with the CES demand model described in Section 2.0. In this paper, we cover only the residential customer impacts for three rate structures: CPP-F, TOU, and CPP-V.

CPP-F Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the CPP-F rate, the average peak-period price on critical days was roughly $0.59 per kWh, the peak price on non-critical days was $0.22 per kWh, and the average off-peak price was $0.09 per kWh. CPP-F rate impacts are as follows:

- On critical days, statewide average reduction in peak-period energy use was estimated to be 13.1 percent. Impacts varied across the four climate zones which

[28] Charles River Associates (2005), Faruqui and George (2005), Herter (2007) and Herter, McAuliffe and Rosenfeld (2007).

spanned a climate as diverse as that of San Francisco and Palm Springs ranged from a low of 7.6 percent to a high of 15.8 percent.

- The average peak-period impact on critical days during the inner summer months (July-September) was estimated to be 14.4 percent while the same impact was 8.1 percent during the outer summer months (May, June, and October).
- On normal weekdays, when just the TOU rate was in effect, the average impact was 4.7 percent, with a range across climate zones from 2.2 percent to 6.5 percent.
- No change in total energy use across the entire year was found based on the average SPP prices.
- The impact of different customer characteristics on energy use by rate period was also examined. Central air conditioning ownership and college education are the two customer characteristics that were associated with the largest reduction in energy use on critical days.

Table 4- Residential CPP-F Rate Impacts on Critical Days for Inner Summer Months (July, August, September)

Year			Start Value (kWh/hr)	Impact (kWh/hr)	Elasticity Estimate	T-stat	Impact (%)
2003	Rate Period	Peak	1.28	-0.163	-	-20.94	-12.71
		Off-peak	0.8	0.021	-	7.8	2.57
		Daily	0.9	-0.018	-	-6.88	-1.95
	Elasticity	Substitution	-	-	0.086	-20.51	-
		Daily	-	-	-0.032	-6.8	-
2004	Rate Period	Peak	1.28	-0.178	-	-18.49	-13.93
		Off-peak	0.8	0.01	-	2.95	1.25
		Daily	0.9	-0.029	-	-8.7	-3.24
	Elasticity	Substitution	-	-	0.087	-16.84	-
		Daily	-	-	-0.054	-8.55	-

Notes:

[1] Estimations are based on the average customer approach. The average customer approach involves using the input values (e.g., weather, central AC saturations and starting energy use values by rate period) for the average customer across all climate zones.
[2] All the numbers are based on average critical day weather in 2003/2004.

TOU Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the TOU rate, the average peak-period price was roughly $0.22 per kWh and the average off-peak price was $ 0.09 per kWh.

- The reduction in peak period energy use during the inner summer months of 2003 was estimated to be 5.9 percent. However, this impact completely disappeared in 2004.
- Due to small sample problems in the estimation of TOU impacts, normal weekday elasticities from the CPP-F treatment may serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates.

CPP-V Impacts

These customers were located in the San Diego metropolitan area. The average price for customers on the standard rate was about $0.14 per kWh. Under the CPP-V rate, the average peak-period price on critical days was roughly $0.65 per kWh and the average off-peak price was $0.10 per kWh. This rate schedule was tested on two different treatment groups. Track A customers were drawn from a population with energy use greater than 600 kWh per month. In this group, average income and central AC saturation was much higher than the general population. Track A customers were given a choice of installing an enabling technology and about two thirds of them opted for the enabling technology. The Track C group was formed from customers who previously volunteered for a smart thermostat pilot. All Track C customers had central AC and smart thermostats. Hence, two-thirds of Track A customers and all Track C customers had enabling technologies.

As shown in Table 5, Track A customers reduced their peak-period energy use on critical days by about 16 percent (about 25 percent higher than the CPP-F rate impact). Track C customers reduced their peak-period use on critical days by about 27 percent.

A comparison of the CPP-F and the CPP-V results shows that usage impacts are significantly larger with an enabling technology than without it.

Table 5- Residential CPP-V Rate Impacts for Summer for All Customers

			Start Value (kWh/hr)	Impact (kWh/hr)	Elasticity Estimate	t-stat	Impact (%)
Track A	Rate Period	Peak	2.14	-0.3374	-	-10.89	-15.76
		Off-peak	1.33	0.0445	-	4.26	3.34
		Daily	1.46	-0.0187	-	-1.71	-1.28
		Weekend Daily	1.3	0.0173	-	2.72	1.33
	Elasticity	Substitution	-	-	-0.111	-11.76	-
		Daily	-	-	-0.027	-1.7	-
		Weekend Daily	-	-	-0.043	-2.74	-
Track C	Rate Period	Peak	2.33	-0.635	-	-35.03	-27.23
		Off-peak	1.26	0.044	-	3.19	3.52
		Daily	1.43	-0.059	-	-9.85	-4.17
		Weekend Daily	1.34	0.016	-	4.1	1.2
	Elasticity	Substitution	-	-	-0.077	-10.61	-
		Technology Impact-Substitution	-	-	-0.214	-24.04	-
		Daily	-	-	-0.044	-3.49	-
		Technology Impact-Daily	-	-	-0.019	-3.49	-
		Weekend Daily	-	-	-0.041	-4.12	-

Notes:

[1] Estimations are based on average customer approach.
[2] Track A analysis was conducted for summer 2004.
[3] Track C analysis pools summers 2003 and 2004 and estimates a single model.

3.4 Colorado- Xcel Energy TOU Pilot[29]

In the summer of 2006, Xcel Energy initiated a pilot program that tested the impact of TOU and CPP rates, as well as enabling technologies, on consumption in the Denver metropolitan area. The effective treatment period lasted about a year, from July 15, 2006 through July 15, 2007. Approximately 3,700 residential customers initially volunteered into the pilot program. Approximately 26 percent of those customers left the pilot by the end, leaving a final sample of about 2,900 participants.[30] All customers had interval meters installed prior to the pilot program which could wirelessly transmit consumption to mobile vehicles collecting the household data. Some customers were offered enabling technologies—AC cycling switches and Programmable Communicating Thermostats (PCT)—in addition to the tested rate structures. Customers were subject to one of the three rate options:

- Time-of-use (RTOU): Higher price during on-peak periods and a lower price during off-peak periods

[29] Based on Energy Insights, Inc, (2008a) and (2008b).

[30] The report notes that, because customers who want to participate are included in the pilot, there is an inherent self selection bias involved.

- Critical peak (RCPP): Critical peak prices up to 10 summer days; lower off-peak prices at all other times and notification of critical peak days by 4 pm the day before.
- Time-of-use+ critical peak (RCTOU): Higher on-peak price (lower than the RTOU on-peak prices), lower off-peak prices, and critical peak prices up to 10 summer days

Table 6 illustrates the demand response impacts from the treatment groups during critical peak, on-peak, and off-peak hours in the summer months of pilot period.[31] All results presented below were determined to be statistically significant. Participants subject to critical peak pricing reduced demand during peak hours substantially more so than customers not subject to CPP. Nevertheless, all groups experienced some reduction in demand. It is important to note that the results of the experiment may be subject to self-selection bias given the nature of the process through which they were recruited. Thus, the results may not generalize to the population at large.

Table 6- Demand Response Impacts

Rate	Enabling Technology	Central AC	Critical Peak	On Peak	Off Peak
TOU	None	No	-	-10.63%	-2.95%
TOU	None	Yes	-	-5.19%	-0.27%
CPP	None	No	-31.91%	-	-0.08%
CPP	None	Yes	-38.42%	-	0.59%
CPP	AC Cycling Switch	Yes	-44.81%	-	1.34%
CTOU	None	No	-15.12%	-2.51%	8.69%
CTOU	None	Yes	-28.75%	-8.21%	3.56%
CTOU	AC Cycling Switch	Yes	-46.86%	-10.63%	4.00%
CTOU	PCT	Yes	-54.22%	-10.29%	2.96%

Xcel Energy notes in the conclusion to its report that the pilot was conducted as a proof of concept rather than a technology test.[32] While the demand reduction was significant, the meters implemented in the pilot were too expensive to make the offerings cost-effective.

[31] As defined above, the summer months of the pilot included June, July, August, and September. As the pilot started in July of 2006 and ended in July of 2007, impacts were not measured for the months of June of 2006, and August and September of 2007.

[32] Energy Insights, Inc. (2008b).

3.5 Florida- The Gulf Power Select Program[33]

In 2000, Gulf Power, a subsidiary of the Southern Company, started a unique demand response program that provides customers with three different service options. The first option is a standard residential service (RS) pricing option which involved a standard flat rate with no time varying rates. The second optional is a conventional TOU pricing option (RST) with two pricing periods. The third option is the Residential Service Variable Price (RSVP) pricing option which is a three-period CPP tariff.

Under the RSVP option, Gulf Power provides the price signals and customers modify their usage patterns through a combination of the price signals and advanced metering and appliance control. Gulf Power markets the RSVP option under the GoodCents Select program and charges the participants a monthly participation fee. By the end of 2001, approximately 2,300 homes were served by the RSVP.

Table 7 shows the rates under the Gulf Power demand response program.

Table 7- Residential Tariffs for Summer Months

Program	Period	Charge	Applicable
RS	Base	$0.057/kWh	All hours
RST	Off-peak	$0.027/kWh	12 a.m.-12 p.m. and 9 p.m.-12 a.m.
RST	Peak	$0.104/kWh	12 p.m.- 9 p.m.
RSVP	Off-peak	$0.035/kWh	12 a.m.-6 a.m. and 11 p.m.-12 a.m.
RSVP	Mid-peak	$0.046 /kWh	6 a.m.-11 a.m. and 8 p.m.-11 p.m.
RSVP	Peak	$0.093/kWh	11 a.m.-8 p.m.
RSVP	CPP	$0.29/kWh	When called

Gulf Power reports the base coincident peak demand as 6.1 KW per household (hh). RSVP program performance results presented in Table 8 show that program participants reduce their demand by 2.75 KW per household during the critical peak period or a 41 percent reduction in energy usage during the critical peak period.

Table 8- RSVP Program Performance by Period

33 See Appendix B of Borenstein, Jaske, and Rosenfeld (2002), which is adapted from Levy, Abbott and Hadden (2002).

Impact Type	Period	Impact
Average Demand Reduction	Peak Critical Peak	2.1 kW/hh 2.75 kW/hh
Average Energy Reduction	Peak Critical Peak	22% 41%

3.6 France- Électricité de France (EDF) Tempo Program[34]

Électricité de France (EDF) initiated the Tempo program in 1996. This is a full-scale voluntary program and is not a controlled experiment. The rate design entails two pricing periods, peak and off-peak and three day types. The peak period is 16 hours long, from 6 am to 10 pm, and the off-peak period is 8 hours long. Under the program, the year is divided into three day-types:

- *Blue days* are the least expensive 300 days.
- *White days* are moderately priced 43 days.
- *Red days* are the most expensive 22 days.

The prices per kWh, expressed in Euro cents, are shown below:

	Blue Days	White Days	Red Days
Off-Peak Period	4.64	9.48	17.62
Peak Period	5.77	11.25	49.29

Customers learn which day would be in effect the next day through the use of several resources including the web, call-centers, subscription to e-mail alerts and by plugging in an electrical device.

EDF implemented a pilot program before launching the Tempo rate on a full-scale basis. The pilot program set prices that were much higher than the Tempo prices. The own-price elasticity for peak demand was estimated at -0.79, much higher than any of the estimates for U.S. pilots, and the own-price elasticity for off-peak usage was estimated to be -0.18.[35]

[34] For a recent presentation, see Giraud (2004). For earlier analysis, see Giraud and Aubin (1994) and Aubin, Fougere, Husson and Ivaldi (1995). For the current tariff, consult http://www.edf-bleuciel.fr/accueil/mon-quotidien-avec-bleu-ciel-d-edf/option-tempo-41090.html&onglet=5.

[35] Matsukawa (2001) found similarly high price elasticities using data on 279 households in Japan. For households with electric water heaters, he estimated an own-price elasticity of -0.768 for the peak period -

3.7 Idaho- Idaho Residential Pilot Program[36]

Idaho Power Company initiated two residential pilot programs in the Emmett area of Idaho in the summer of 2005 and the summer of 2006: Time-of-day (TOD) and Energy Watch (EW).

Time-of-Day Pilot

The TOD pilot was designed as a conventional TOU program where the participants were charged different rates by time of the day as shown in Table 9. The TOD pilot included 85 treatment and 420 control group customers as of August 2006.

Table 9- Rate Design for the Time-of-Day Pilot

Period	Charge	Applicable
On-Peak	\$0.083/kWh	Weekdays from 1pm to 9pm
Mid-Peak	\$0.061/kWh	Weekdays from 7am to 1pm
Off-Peak	\$0.045/kWh	Weekdays from 9pm to 7am and all hours on weekends and holidays

As shown in Table 10, the results from the TOD pilot for the summer of 2006 show that, on average, the peak period percentage of total summer usage was the same for the treatment and control groups – about 22 percent. In fact, the percentage of usage during the mid-peak and off-peak periods was also the same between the two groups. This indicates that the TOD rates had no effect on shifting usage. However, in light of the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It suggests that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off peak periods.

0.561 for the off-peak period. Similar estimates were obtained for households without electric water heaters and for households on standard rates. Filippini (1995) also found price elasticities in this range using Swiss data.

36 Idaho Power Company (2006).

Table 10- Summer 2006 (June-August) Usage under the TOD Pilot

	Average Use (kWh)		% of Total Summer Use		Program Impact	
Period	Treatment	Control	Treatment	Control	Difference (Control- Treatment)	T-stat
On-Peak	800	763	22%	22%	-36.46	0.66
Mid-Peak	591	568	16%	16%	-22.43	0.52
Off-Peak	2307	2162	62%	62%	-145.78	0.99
Summer 06 Usage	3698	3493	100%	100%	-204.67	0.87

Energy Watch Pilot

The Idaho Power Company Energy Watch (EW) pilot was designed as a CPP pilot where the participants were notified of the CPP event on a day-ahead basis. A total of 10 EW days were called during the summer of 2006. EW featured CPP hours from 5 p.m. to 9 p.m., day-ahead notification, a CPP energy price of $0.20/kWh and a non-CPP energy price of $0.054/kWh. The EW pilot included 68 treatment and 355 control group customers as of August 2006.

Table 11 shows the reduction in load (kW) on CPP days for each of the event days. Average hourly demand reduction ranged from 0.64 kW (on June 29) to 1.70 kW (on July 27). Average hourly load reduction for all ten event days was 1.26 kW. The average total load reduction for a 4-hour event was 5.03 kW.

Table 11- Energy Watch Day: Load Reductions (kW) On Each of the Ten Event Days

Hour Beginning	Hour Ending	29-Jun	11-Jul	14-Jul	18-Jul	19-Jul	25-Jul	27-Jul	3-Aug	9-Aug	15-Aug	Average
5pm	6pm	0.64	1.31	1.09	1.39	1.2	1.33	1.58	1.14	0.83	1.02	1.17
6pm	7pm	0.69	1.5	1.17	1.43	1.32	1.45	1.62	1.27	1.14	1.15	1.29
7pm	8pm	0.77	1.58	1.16	1.57	1.41	1.55	1.7	1.24	1.02	0.96	1.33
8pm	9pm	0.8	1.48	1.11	1.47	1.27	1.4	1.6	1.13	0.95	0.89	1.25
4-Hour Total		2.89	5.87	4.53	5.85	5.2	5.74	6.5	4.77	3.94	4.02	5.03
Average Hourly		0.72	1.47	1.13	1.46	1.3	1.43	1.62	1.19	0.99	1.01	1.26
Min Temp		68	65	65	61	62	75	68	59	62	67	65
Max Temp		85	100	98	94	98	99	104	92	85	92	95
Avg Temp		75	84	83	79	80	87	87	76	73	80	80

3.8 Illinois- Energy Smart Pricing Plan

The Community Energy Cooperative's ("CEC") Energy-Smart Pricing Plan (ESPP) was the first large-scale residential real-time pricing (RTP) program in the US. It took place in the service territory of Commonwealth Edison in northern Illinois and ran between 2003 and 2006. ESPP initially included 750 participants and expanded to nearly 1,500 customers in 2005. The same number of participants was maintained for the 2006 program year. ESPP focused on low cost technology and tested the hypothesis that major benefits may result from RTP without the adoption of expensive technology.

The ESPP design included day-ahead announcement of the hourly electricity prices for the next day (on the day of the event, customers were charged the hourly prices that had been posted the day before), high-price day notification via phone or email when the price of electricity climbed over $0.10 per kWh (in 2006, the notification threshold was set to above $0.13 per kWh), and a price cap of $0.50 per kWh for participants meaning that the maximum hourly price is set at $0.50 per kWh during their participation in the program. In 2005 (continued in 2006), cycling switches for central air conditioners were installed at participants homes, which effectively reduced energy consumption by AC units during high price periods. In 2006, the Energy PriceLight, a glass orb similar in design to the Energy Orb used by several utilities, was distributed. The Energy PriceLight is a glass orb that receives wireless price information and relays this information, i.e. high or low electricity prices, by glowing in different colors.

Pilot Program Results for 2005[37]

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy consumption. A regression analysis using a simple double-log specification with hourly usage as the dependent variable and hourly price and weather as the independent variables was used to estimate the price elasticity of demand for the summer months. Overall, the price elasticity during the summer of 2005 was estimated to be -0.047.

[37] Summit Blue Consulting (2006).

With enabling technology, i.e. automatic cycling of the central-air conditioners during high-price periods, the overall price elasticity increased to -0.069. The largest response occurred on high-price notification days. For instance, on the day with the highest prices during the summer of 2005, participants reduced their peak hour consumption by 15 percent compared to what they would have consumed under the flat ComEd residential rate. Price responsiveness varied over the course of a day. Own price elasticities by time of day are presented in Table 12.

Table 12- Elasticity Estimates from ESPP

Time of the Day	Elasticity Estimate
Daytime (8 a.m. to 4 p.m.)	-0.02
Late afternoon/evening hours (4 p.m. to midnight)	-0.03
Daytime+ High-Price Notification	-0.02
Late Daytime/Evening+High-Price Notification	-0.05

The impact analysis indicated that ESPP participants consumed 35.2 kWh less per month during the summer months compared to what they would have consumed without the ESPP. These savings represented roughly three to four percent of summer electricity usage. Statistically significant savings were not found for winter usage which is not surprising since most high price days occur in the summer months in this area. Overall, ESPP resulted in a net decrease in monthly energy consumption.

Pilot Program Results for 2006[38]

Results from the analysis of the ESPP in 2006 supported the findings of program's previous years. The price elasticity during the summer of 2006, for hours when the price of electricity was equal to or below $0.13 per kWh, was estimated to be -0.047. The price elasticity for the same period, but for hours when the price of electricity was above $0.13 per kWh, was estimated to be -0.082. The Energy PriceLight improved customer responsiveness resulting in an elasticity of -0.067 across all hours. For customers with A/C cycling, the price elasticity for high price periods was estimated at -0.098.

Results of the energy impact analysis indicated that ESPP participants consumed 16.7 kWh less per month, year round, relative to individuals not on the ESPP rate. During the summer months, participants consumed an additional 10.0 kWh less per month, or equivalently

38 Summit Blue Consulting, (2007).

26.7 kWh less per month total. This translates to approximately three percent of summer electricity usage, similar to the savings results of the 2005 program year. Again, on the whole, ESPP resulted in a decrease in monthly energy consumption.

3.9 Missouri- AmerenUE Critical Peak Pricing Pilot

First Year of the Pilot Program (2004)[39]

AmerenUE in association with the Missouri Collaborative formed by the Office of Public Counsel (OPC), the Missouri Public Service Commission (MPSC), the Department of Natural Resources (DNR) and two industrial intervener groups initiated a residential TOU pilot study in Missouri during the spring of 2004. Program impacts associated with three different TOU programs were evaluated: TOU with peak, mid-peak and off-peak periods; TOU with a CPP component; and TOU with a CPP component and an enabling technology (smart thermostat). Table 13 shows the pilot rates. .

Table 13- Residential TOU Experiment Summer Rate Design

Program	Time	Charge	Applicable
TOU	Off Peak	$0.048/kWh	Weekday 10pm–10am, weekends, holidays
TOU	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU	Peak	$0.183/kWh	Weekdays 3pm – 7pm
TOU-CPP	Off Peak	$0.048/kWh	Weekdays 10pm–10am, weekends, holidays
TOU-CPP	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU-CPP	Peak	$0.168/kWh	Weekdays 3pm – 7pm
TOU-CPP	CPP	$0.30/kWh	Weekdays 3pm – 7pm, 10 times per summer

Table 14 shows the number of participants in the treatment and control groups by type of rate.

Table 14- Experiment Sample Allocation

Treatment	Treatment Sample Size	Control Sample Size
TOU	88	89
TOU-CPP	85	89
TOU-CPP-Tech	77	117
Total	250	295

39 RLW Analytics, (2004).

The following results are based on the data compiled from the pilot between June 1, 2004 and September 30, 2004. Table 15 shows that the participants in the TOU and TOU-CPP groups did not shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. Off-peak consumption increased and peak consumption decreased only slightly for the treatment groups compared to the control groups for both TOU and TOU-CPP programs. However, none of these differences in consumption between the treatment and control groups are statistically significant. Table 16 shows that the TOU-CPP-Tech group reduced their average CPP period demand by 35 percent compared to the control group on the event days. TOU-CPP group reduced their demand by 12 percent during the same period. Both impacts are statistically significant at the five percent level.

Table 15- Average Participant Use by Program and Time Period- 2004

Program	June 1-September 30 Period	Control Group (kWh)	Treatment Group (kWh)	Difference (Control-Treatment)	T-test	Pr> |t|	Statistical Significance of the Difference
TOU	Off Peak	33.63	34.87	-1.24	-0.71	0.479	Not Significant.
TOU	Mid Peak	23.59	22.78	0.81	0.71	0.476	Not Significant.
TOU	On Peak	13.81	13.36	0.45	0.67	0.505	Not Significant.
TOU	Seasonal	60.00	60.34	-0.34	-0.12	0.905	Not Significant.
TOU-CPP	Off Peak	35.84	38.36	-2.52	-1.19	0.235	Not Significant.
TOU-CPP	Mid Peak	24.11	24.54	-0.43	-0.34	0.733	Not Significant.
TOU-CPP	On Peak	13.82	13.29	0.53	0.73	0.466	Not Significant.
TOU-CPP	CPP	19.8	18.85	0.95	0.86	0.390	Not Significant.
TOU-CPP	Daily	62.87	65.3	-2.43	-0.72	0.473	Not Significant.
TOU-CPP-Tech	Off Peak	37.61	33.31	4.3	2.44	0.002	Significant.
TOU-CPP-Tech	Mid Peak	25.86	22.47	3.39	3	0.003	Significant.
TOU-CPP-Tech	On Peak	14.86	12.77	2.09	3.09	0.002	Significant.
TOU-CPP-Tech	CPP	21.39	15.48	5.91	6.5	0.000	Significant.
TOU-CPP-Tech	Daily	66.63	58.28	8.35	2.88	0.000	Significant.

Table 16- Average CPP Period Demand on the 6 Event Days in Summer 2004

Program	Control Group (kW)	Treatment Group (kW)	Difference (Control-Treatment)	% Difference	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	4.98	4.37	0.61	12%	2.09	0.038	Significant.
TOU-CPP-Tech	5.36	3.49	1.87	35%	8.09	0.000	Significant.

Second Year of the Pilot Program (2005)[40]

During the second year, the first year rate design was maintained. Table 17 provides average participant usage by time period and program while Table 18 summarizes the average demand in the peak periods of eight CPP days in the summer of 2005. In 2005, the TOU-CPP and TOU-CPP-Tech customers reduced their usage during CPP periods by statistically significant amounts. However, seasonal usage reductions are not statistically significant at five percent level. Average CPP period demand reduction during eight event days is 13 percent for TOU-CPP customers and 24 percent for TOU-CPP-Tech customers. Both impacts are statistically significant at five percent.

Table 17- Average Participant Use by Program and Time Period – 2005

Program	Jun 1- Aug 31 Period	Control Group (kWh)	Treatment Group (kWh)	Difference (Control-Treatment)	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	Off Peak	4495	4450	45	0.28	0.78	Not Significant.
TOU-CPP	Mid Peak	2054	2019	35	0.54	0.59	Not Significant.
TOU-CPP	On Peak	927	896	31	0.96	0.34	Not Significant.
TOU-CPP	CPP	252	219	33	3.92	0.00	Significant.
TOU-CPP	Seasonal	7,729	7,584	145	0.58	0.56	Not Significant.
TOU-CPP-Tech	Off Peak	4147	4017	130	0.91	0.37	Not Significant.
TOU-CPP-Tech	Mid Peak	1934	1901	33	0.46	0.65	Not Significant.
TOU-CPP-Tech	On Peak	884	863	21	0.64	0.52	Not Significant.
TOU-CPP-Tech	CPP	240	182	58	5.99	0.00	Significant.
TOU-CPP-Tech	Seasonal	7,205	6,963	242	0.98	0.33	Not Significant.

Table 18- Average CPP Period Demand on Eight Event Days in Summer 2005

Program	Control Group (kW)	Treatment Group (kW)	Difference (Control-Treatment)	% Difference	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	5.56	4.84	0.72	13%	3.9	0.0001	Significant.
TOU-CPP-Tech	5.29	4.05	1.14	24%	6.05	0.0001	Significant.

40 Voytas (2006).

3.10 New Jersey- GPU Pilot[41]

GPU offered a residential TOU pilot program with a critical peak price and enabling technology component in the summer of 1997. The rate design involved three price tiers (peak, shoulder, and off-peak) and a critical peak price that is only effective for a limited number of high-cost summer hours. Moreover, the pilot program tested the impacts from two sets of alternative rates by allocating treatment customers to two groups and subjecting each group to one of the two sets. Table 19 shows the control and treatment group rate designs.

Table 19- Experimental Rate Design

Group	Charge	Applicable
Control	Standard increasing-block residential tariff: $0.12/kWh if consumption <=600kWh per month $0.153/kWh if consumption >600kWh per month	All hours
Treatment Group 1 (High shoulder/peak design)	Off-peak: $0.065/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays; All day on weekends and holidays.
	Shoulder:$0.175/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.30/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	When called during peak period
Treatment Group 2 (Low shoulder/peak design)	Off-peak:$0.09/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays; All day on weekends and holidays.
	Shoulder:$0.125/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.25/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	When called during peak period

One important feature of this pilot is that communication equipment was installed in customer premises allowing them to preset their set points during the critical periods. Analysis of the hourly load data for each of the treatment and control group customers collected for the period of June through September 1997 revealed the following results. On non-critical weekdays, the largest usage reductions in the average hourly load were observed during the peak period and averaged to 0.53 KW or 26 percent relative to the control group. Load reductions were also observed during the late-morning shoulder period, but these reductions were limited compared to those during the peak period. The treatment group with the high rate design reduced usage by roughly 50 percent more during each of peak and shoulder periods than the treatment group with the low-rate design. On CPP days, the results were similar to those on the non-CPP weekdays; though larger in magnitude, especially during the peak period. In the first hour of the peak period, average load reduction was 1.24 KW or a 50 percent reduction compared to the

[41] Braithwait (2000).

control group. During the next two peak hours, the reduction was around 1 KW, later falling to 0.59 KW on the last peak hour. Also, the treatment group usage was substantially larger than the control group during the shoulder and off-peak periods following the critical peak hours.

On weekends, average usage was similar for the control and treatment customers, with slightly lower (though not statistically significant) levels for the treatment customers. Average usage over all days by the treatment group decreased compared to the control group, but the result was not statistically significant. A large portion of these reductions can be attributed to the changes in the weekday usage. Average daily usage on weekend, weekdays, and all days are presented in Table 20.

Table 20- Average Daily Usage for Summer 1997 (kWh)

	Control	Treatment	Usage Difference	% Difference
Weekdays	30.4	28.3	-2.1	-6.9%
Weekends	34.1	33.7	-0.4	-1.2%
All days	32.5	30.9	-1.6	-4.9%

The data were also used to estimate the elasticity of substitution using two alternative models: the constant elasticity of substitution (CES) model discussed earlier in this paper and the more flexible generalized Leontief (GL) model. The substitution elasticity from the CES model was estimated to be 0.30. This estimate was larger than the 0.14 value estimated by EPRI in its analysis of the best five TOU pricing experiments from the late 1970s/early 1980s. The larger substitution elasticity from this pilot can be attributed to the presence of interactive communication equipment through which the customers preset their usage patterns of air conditioning (AC) and other appliances. The GL model allows substitution elasticity estimates to vary by time-period. With this model, the substitution elasticity between peak and off-peak periods was estimated as 0.40, or a third higher than the estimate from the CES model. Substitution elasticities between other time-periods can be seen in Table 21.

Table 21- Substitution Elasticities

Month	Time Period	CES	GL High Rate Tariff	GL Low Rate Tariff
1	Overall	0.306	-	-
	Peak-shoulder	-	0.155	0.166
	Peak-off-peak	-	0.395	0.356
	Shoulder-off-peak	-	0.191	0.187
2	Overall	0.295	-	-
	Peak-shoulder	-	0.055	0.06
	Peak-off-peak	-	0.407	0.366
	Shoulder-off-peak	-	0.178	0.176

3.11 New Jersey- PSE&G Residential Pilot Program [42]

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two sub-programs. Under the first sub-program, *myPower Sense*, participants were educated about the TOU/CPP tariff and were notified of the CPP event on a day-ahead basis. The program assessed the reduction in energy use when a CPP event was called. Under the second sub-program, *myPower Connection*, participants were given a free programmable communicating thermostat (PCT) that received price signals from PSE&G and adjusted their air conditioning settings based on previously programmed set points. A total of 1,148 customers participated in the pilot program; 450 in the control group, 379 in *myPower Sense*, and 319 in *myPower Connection*. PSE&G recruited the participants separately for each group through direct mail with follow-up telemarketing[43]. Customers didn't have the opportunity to choose the treatment they would be receiving. *myPower Sense* customers received a $25 incentive upon enrollment and another $75 was paid upon the conclusion of the program. *myPower Connection* participants were provided free PCTs and received $75 at the end of the program.

The TOU/CPP tariff included a night discount, a base rate, an on-peak adder, and a critical peak adder for the summer months as shown in Table 22.

42 PSE&G and Summit Blue Consulting, (2007).

43 PSE&G recruited pilot participants from Cherry Hill and Hamilton towns as they had high percentages of residents on standard rates and high rates of customer ownership of central air conditioning systems.

Table 22- TOU/CPP Rate Design: Summer Months (June to September 2006 and 2007)

Period	Charge (June to September 2006)	Charge (June to September 2007)	Applicable
Base Price	$0.09/kWh	$0.087/kWh	All hours
Night Discount	-$0.05/kWh	-$0.05/kWh	10 p.m.-9 a.m. daily
On Peak Adder	$0.08/kWh	$0.15/kWh	1 p.m.-6 p.m. weekdays
Critical Peak Adder	$0.69/kWh	$1.37/kWh	1 p.m.-6 p.m. weekdays when called (Added to the base price when called)

PSE&G called two CPP events in Summer 2006 and five CPP events in Summer 2007. Table 23 summarizes the peak demand impacts on these 7 CPP event days. Results show that:

- *myPower Connection* customers reduced their peak demand by 21 percent due to TOU-only pricing. These customers reduced their peak load by an additional 26 percent on CPP event days.
- *myPower Sense* customers with CAC ownership reduced their peak demand by three percent on TOU-only days. On CPP event days, their peak load reductions reached 17 percent. Interestingly, *myPower Sense* customers without CAC ownership achieved six percent peak reductions on TOU-only days while the reductions reached 20 percent on CPP event days.
- *myPower Connection* customers reduced their peak-demand consistently more than *myPower Sense* customers because they had the PCT enabling technology.

Table 23- Estimated Peak Demand Impacts on 2006 and 2007 Summer CPP Event Days (Average kW per Hour)

Impact Estimate	Base Average Peak Consumption (kW)	TOU Impact		CPP Impact		Total Impact	
		kW	%	kW	%	kW	%
myPower Connection	2.85	-0.59	-21%	-0.74	-26%	-1.33	-47%
myPower Sense with CAC	2.6	-0.07	-3%	-0.36	-14%	-0.43	-17%
myPower Sense without CAC	1.61	-0.09	-6%	-0.23	-14%	-0.32	-20%

Source: Summit Blue Consulting

Summit Blue also estimated summer substitution elasticities for *myPower Connection and myPower Sense* customers. Table 24 presents the elasticity estimates and the associated lower and upper bounds for 90 percent confidence level.

As expected, *myPower Connection* customers have the largest elasticity of substitution, followed respectively by *myPower Sense* customers with and without CAC ownership.

Table 24- Estimated Substitution Elasticity for Summers 2006 and 2007

Impact Estimate	Substitution Elasticity	90% Confidence Interval
myPower Connection	0.125	0.12 to 0.131
myPower Sense with CAC	0.069	0.063 to 0.075
myPower Sense without CAC	0.063	0.055 to 0.072

3.12 New South Wales/Australia- Energy Australia's Network Tariff Reform [44]

The TOU pricing program is the largest demand management project by Energy Australia. The price elasticity estimates from the TOU tariffs are presented in Table 25.

Table 25- TOU Price Elasticity Estimates

Type	Season	Peak Own Price Elasticity	Peak to Shoulder Cross Price Elasticity	Peak to Off-Peak Cross Price Elasticity
Residential	Summer 2006 Winter 2006	-0.30 to -0.38 -0.47	-0.07 -0.12	-0.04 -
Business (less than 40 MWh)	Summer 2006 Winter 2006	-0.16 to -0.18 (ns) -0.2 (ns)	-0.03 -	- -
Business (40 MWh to 160 MWh)	Summer 2006 Winter 2006	-0.03 to -0.13 (ns) -0.02 to -0.09 (ns)	- -	- -

Note: ns refers to "not statistically significant"

The TOU results show that slight energy conservation effects resulted from residential consumption under TOU rates; the conservation effects were larger in winter than in summer for the residential customers and business customer price elasticities are not statistically significant.

Energy Australia started the Strategic Pricing Study in 2005 which included 1,300 voluntary customers (50 percent business, 50 percent residential customers). The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and

[44] Colebourn (2006).

online access to data. Study participants received dynamic peak price signals through Short Message Service (SMS), telephone, email, or the display unit.

Preliminary results that are available from three dynamic peak pricing (DPP) events show that residential customers reduced their dynamic peak consumption by roughly 24 percent for DPP high rates (A$2+/kWh) and roughly 20 percent for DPP medium rates (A$1+/kWh). Response to the 2nd DPP event was greater than that to the 1st DPP event. This may be attributed to the day-ahead notification under the 2nd DPP event (versus day-of notification under the 1st DPP event) and/or temperature differences. Response to the 2nd event was also greater than to the 3rd DPP event. This may be explained by lower temperatures on the 3rd DPP event which may have led to less discretionary appliances to turn off.

3.13 Ontario/Canada- Ontario Energy Board's Smart Price Pilot[45]

The Ontario Energy Board operated the residential Ontario Smart Price Pilot (OSPP) between August 2006 and March 2007. The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures:

- The existing Regulated Price Plan (RPP) TOU: The RPP TOU rates are shown in Table 26.
- RPP TOU rates with a CPP component (TOU CPP). The CPP was set at C$0.30 per kWh based on the average of the 93 highest hourly Ontario electricity prices in the previous year. The RPP TOU off-peak price was decreased to C$0.031 (from C$0.035) per kWh to offset the increase in the critical peak price. The maximum number of critical day events was set at nine days, however only seven CPP days were called during the pilot.
- RPP TOU rates with a critical peak rebate (TOU CPR): The CPR provided participants with a C$0.30 per kWh rebate for each kWh of reduction from estimated baseline consumption. The CPR baseline consumption was defined as the average usage during the same hours over the participants' last five non-event weekdays, increased by 25 percent.

Table 26- Regulated Price Plan (RPP) TOU Rate Design

45 Ontario Energy Board, (2007).

Season	Time	Charge	Applicable
Summer (Aug 1- Oct 31)	Off-peak	C$0.035/kWh	10 p.m.- 7 a.m. weekdays; all day on weekends and holidays
Summer (Aug 1- Oct 31)	Mid-peak	C$0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays
Summer (Aug 1- Oct 31)	On-peak	C$0.105/kWh	11 a.m.- 5 p.m. weekdays

A total of 373 customers participated in the pilot: 124 in TOU-only, 124 in TOU-CPP, and 125 in TOU-CPR. The control group included 125 participants who had smart meters installed but continued to pay non-TOU rates.

The OSPP results show that the load shift during the critical hours of the four summer CPP events ranged between 5.7 percent and 25.4 percent.[46] They also showed that the load shift during the entire peak period of the four summer CPP events ranged between 2.4 percent and 11.9 percent.

Table 27 shows the shift in load during the summer CPP events as a percentage of the load in critical peak hours and of the entire peak period. It is important to note that the percentage reductions for the TOU-only customers are not significant at the 90 percent confidence level.

Table 27- Percentage Shift in Load during the Four Summer CPP Events

Period	TOU- only	TOU- CPP	TOU- CPR
Shift as % of critical peak hours	5.7%	25.4%	17.5%
Shift as % of all peak hours	2.4%	11.9%	8.5%

This study also analyzed the total conservation impact during the full pilot period. The total reduction in electricity consumption due to program impacts is reported in Table 28. The average conservation impact across all customers was estimated to be six percent.

Table 28- Total Conservation Effect for the Full Pilot Duration

[46] Under the OSPP, 3 to 4 hours of the peak period were defined as critical on a CPP day.

Program	% Reduction in Total Electricity Usage
TOU-only	6.0%
TOU- CPP	4.7% (ns)
TOU- CPR	7.4%
Average Impact	6.0%

3.14 WASHINGTON (SEATTLE SUBURBS)- PUGET SOUND ENERGY (PSE)'S TOU PROGRAM[47]

PSE initiated a TOU program for its residential and small commercial customers in 2001. The rate design involved four price periods. Prices were most expensive during the morning and evening periods with mid-day and economy periods following these most expensive periods. Some 300,000 PSE customers were placed in the program and given the option to go back to the standard rates if they were not satisfied with the program. The peak price was roughly 15 percent higher than the average price that prevailed before the program and the off-peak price was 15 percent lower. In 2002, the second year of the program, customers were charged a monthly fee of $1 per month for meter-reading costs. The results of PSE's quarterly report revealed that the 94 percent of the customers paid an extra $0.80 (the total of $0.20 power savings and $1 meter reading costs) by participating in the pilot. This was in contrast with the first year results where customers were not charged meter reading costs and around 55 percent of them experienced bill savings. As a result of customer dissatisfaction and negative media coverage, PSE ceased its TOU program.

Several lessons can be derived from this experience. First, modest price differentials between peak and off-peak may induce customers to shift their load if they are accompanied with unusual circumstances such as the energy crisis of 2000-2001 in the West. An independent analysis of the program found that customers lowered peak usage by five percent per month over a 15 month period, with reductions being slightly higher in the winter months and slightly lower in the summer months. It is important to provide the customers with accurate expectations about their bill savings. The pilot over-promised savings and when these did not materialize, there was a significant backlash against the very premises of the program and the intentions of the utility. Finally, it is essential to offer a pilot program before implementing a full-scale program.

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47 Faruqui and George (2003).

3.15 WASHINGTON- THE OLYMPIC PENINSULA PROJECT[48]

The Olympic Peninsula Project was a component of the Pacific Northwest GridWise Testbed Demonstration that took place in Washington and was led by the Pacific Northwest National Laboratory (PNNL). The Peninsula Project tested whether automated two-way communication systems between grid and passive resources (i.e., end use loads and idle distributed generation) and the use of price signals as instruments would be effective in reducing the stress on the system. Our review focuses on the residential response and does not cover the impacts associated with the distributed generation resources.

By the end of 2005, the project recruited participants with the assistance of the local utility companies. The project received a mailing list from the utilities of the potential participants who had high-speed internet, electric HVAC systems, electric water heater, and electric dryer. Letters were mailed to these customers to recruit potential participants. At the end of the recruiting process, 112 homes were installed with the two-way communication equipments that allowed utilities to send the market price signals to the consumers and allowed consumers to pre-program their demand response preferences. These residential participants were then evenly divided into three treatment groups and a control group. Equipment was also installed in the control group homes but they were given no additional information.

Each treatment group was assigned to one of the three electricity contracts: Fixed-prices that were constant across time; time-of-use/critical peak prices (TOU/CPP); and real time prices. In the last category, participants were able to program their appliance preferences over the web but they still had the option to override their preferences at any time.

Table 29 shows the prices that prevailed under fixed price and TOU/CPP contracts.

48 Pacific Northwest National Laboratory (2007).

Table 29- Experimental Rate Design

Contract	Season	Period	Charge	Applicable
Time-of-Use/ CPP	Spring (1 Apr-24 Jul) and Fall/Winter (1 Oct-31 Mar)	Off-peak	$0.04119/kWh	9 am-6pm and 9pm-6am
		On-peak	$0.1215/kWh	6am-9am and 6pm-9pm
		Critical	$0.35/kWh	Not called
	Summer (25 Jul- 30 Sep)	Off-peak	$0.05/kWh	9am-3pm
		On-peak	$0.135/kWh	3pm-9pm
		Critical	$0.35/kWh	When called
Fixed-Price	All seasons	All day	$0.081/kWh	All hours

The fixed-price group saved two percent on their average monthly bill compared to the control group; the time-of-use pricing group saved 30 percent and the real time pricing group saved 27 percent. Differences in average energy consumption between the contract groups were small but statistically significant. The time-of-use group consumed 21 percent less energy and achieved conservation benefits from time-of-use pricing. The real time group consumed as much as the control group. The fixed-price group used four percent more energy than the control group. The usage comparison across the contract groups is presented in Table 30.

Table 30- Average Daily Energy Consumption per Home (April 06- December 06)

Contract Type	Average Daily Energy Consumption (kWh)	Standard Deviation(kWh)	Percentage Difference (compared to the control)
Control	47	24	0%
Fixed	49	22	4%
Time-of-Use	39	29	-21%
Real-Time	47	26	0%

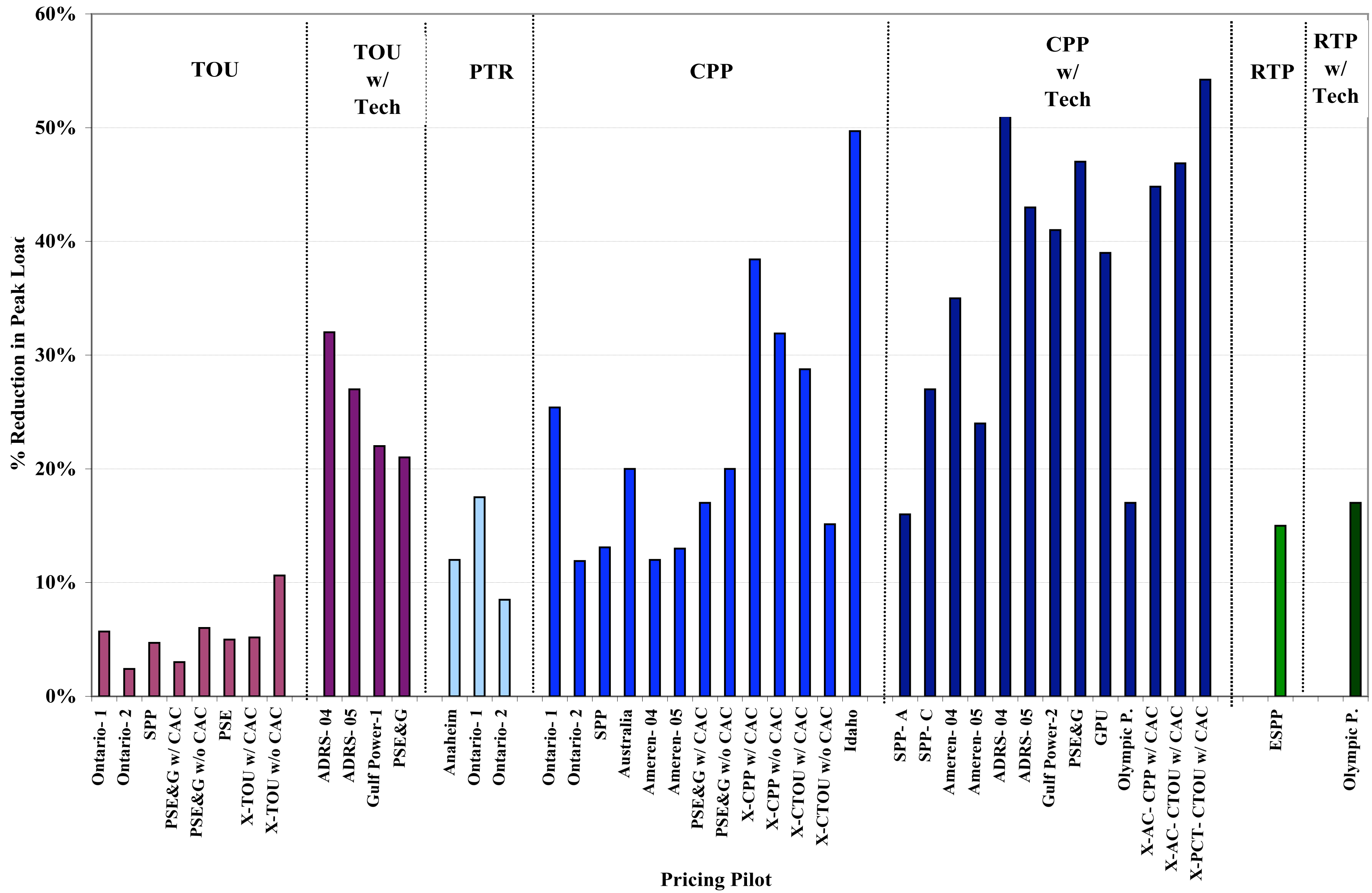
Examination of the residential load shapes by contract and season revealed that the time-of-use/CPP contract was the most effective design at reducing peak-demand. On average, the real-time contract did not bring about the lowest average peak demand. Preliminary analysis of the data reveals that peak demand consumption fell by 15-17% for RTP group, while it fell by 20% for the TOU/CPP group relative to the fixed price group.[49]

4.0 CROSS-EXPERIMENTAL ASSESSMENT

49 Kiesling (2008).

Our review of the 15 pricing experiments reveals that the demand response impacts from different pilot programs vary widely due to the difference in the rate designs tested, use of enabling technologies, ownership of central air conditioning and more generally, due to the variations in sample design. Figure 1 presents a summary.

Figure 1:



60%
50%
40%
30%
20%
10%
0%
% Reduction in Peak Loac
TOU
TOU w/ Tech
PTR
CPP
CPP w/ Tech
RTP
RTP w/ Tech
Ontario- 1
Ontario- 2
SPP
PSE&G w/ CAC
PSE&G w/o CAC
PSE
X-TOU w/ CAC
X-TOU w/o CAC
ADRS- 04
ADRS- 05
Gulf Power-1
PSE&G
Anaheim
Ontario- 1
Ontario- 2
Ontario- 1
Ontario- 2
SPP
Australia
Ameren- 04
Ameren- 05
PSE&G w/ CAC
PSE&G w/o CAC
X-CPP w/ CAC
X-CPP w/o CAC
X-CTOU w/ CAC
X-CTOU w/o CAC
Idaho
SPP- A
SPP- C
Ameren- 04
Ameren- 05
ADRS- 04
ADRS- 05
Gulf Power-2
PSE&G
GPU
Olympic P.
X-AC- CPP w/ CAC
X-AC- CTOU w/ CAC
X-PCT- CTOU w/ CAC
ESPP
Olympic P.
Pricing Pilot

Notes:

*Percentage reduction in load is defined relative to different bases in different pilots. The following notes are intended to clarify these different definitions.

1. TOU with Technology (TOU w/ Tech) and CPP with Technology (CPP w/ Tech) refer to the pricing programs that had some form of enabling technologies.
2. TOU program impacts are defined relative to the usage during peak hours unless otherwise noted.
3. CPP program impacts are defined relative to the usage during peak hours on CPP days unless otherwise noted.
4. Ontario- 1 refer to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPP day. Ontario- 2 refer to the percentage impacts of the programs during the entire peak period on a CPP day.
5. TOU impact from the SPP is based on the CPP-F treatment effect for normal weekdays on which critical prices were not offered.
6. ADRS- 04 and ADRS- 05 refer respectively to the 2004 and 2005 impacts. ADRS impacts on non-event days are represented in the TOU with Technology section.
7. CPP impact for Idaho is derived from the information provided in the reviewed study. Average of kW consumption per hour during the CPP hours (for all 10 event days) is approximately 2.5 kW for a control group customer while this value is 1.2 kW for a treatment group customer. Percentage impact from the CPP treatment is calculated as 50%.
8. Gulf Power-1 refers to the impact during peak hours on non-CPP days and therefore shown in the TOU with Technology section while Gulf Power- 2 refers to the impact during CPP hours on CPP days.
9. Ameren- 04 and Ameren- 05 refer to the impacts respectively from the summers of 2004 and 2005.
10. SPP- A refers to the impacts from the CPP-V program on Track A customers. Two thirds of Track A customers had some form of enabling technologies.
11. SPP- C refers to the impacts from the CPP-V program on Track C customers. All Track C customers had smart thermostats.
12. X-CPP program only differentiates between CPP and non-CPP hours while X-CTOU program differentiates between CPP, on-peak, and off-peak hours.

To synthesize the information from the 15 pricing experiments, we have constructed a dataset of 28 observations where the impacts are grouped with respect to the rate designs and the existence of an enabling technology. Table 31 provides the mean impact estimates and the 95% confidence intervals associated with the mean values from this dataset.

Table 31- Summary Impacts

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	4%	3%	6%	2%	6%
TOU w/ Technology	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	8	17%	13%	20%	12%	25%
CPP w/ Technology	8	36%	27%	44%	16%	51%

Notes:

1- Confidence intervals are calculated assuming normal distribution of the impact estimates.

2- The pilot results from Xcel Energy are excluded from the summary statistics due to the role of self-selection bias, as reported in the study, in driving the large demand impacts.

3- The CPP impact for Idaho is also excluded from the summary statistics since it is an outlier.

On average, TOU programs are associated with a mean reduction of four percent in peak usage, and a 95 percent confidence interval ranges from three to six percent. CPP programs reduce peak usage by 17 percent and a 95 confidence interval ranges from 13 to 20 percent. CPP programs supported with enabling technologies reduce peak usage by 36 percent and a 95 confidence interval ranges from 27 to 44 percent. Impacts associated with PTR and TOU supported with enabling technology programs are also provided in Table 31. However, all these results should be interpreted with caution due to the small number of observations underlying the distributions. Nine out of the twelve impact estimates with enabling technologies are tested on customers with CAC ownership, so these impacts also capture impacts due to CAC ownership.

Our survey finds that in addition to displaying a wide variation in the size of impact due to different rate designs, the impacts also vary widely among the experiments using the same rate design. The residual variation comes from variation in price elasticities and in sample design. Substitution elasticities from the experiments range from 0.07 to 0.40 while the own price elasticities range from -0.02 to -0.10. Availability of the enabling technologies, ownership of central air conditioning and the type of the days examined (weekend vs. weekday) are some of the factors that lead to variations in the elasticities.

A question of great interest to policy makers is how the impact estimates vary across price levels. To address this question, we have to focus on a single experiment which has a high quality design and sufficient data to carry out the simulation. For this purpose, we have focused on the California SPP experiment data whose results have been codified into a widely available tool called PRISM (Price Impact Simulation Model).[50]

PRISM predicts the changes in electricity usage that are induced by time-varying rates by utilizing a constant elasticity of substitution (CES) demand system. PRISM has the capability to predict these changes for peak and off-peak hours for both critical and non-critical peak days. Moreover, PRISM allows predictions to vary by other exogenous factor such as the saturation of central air conditioning and variations in climate. The model can be set to demonstrate these impacts on different customer types. Appendix provides a brief discussion of the PRISM model.

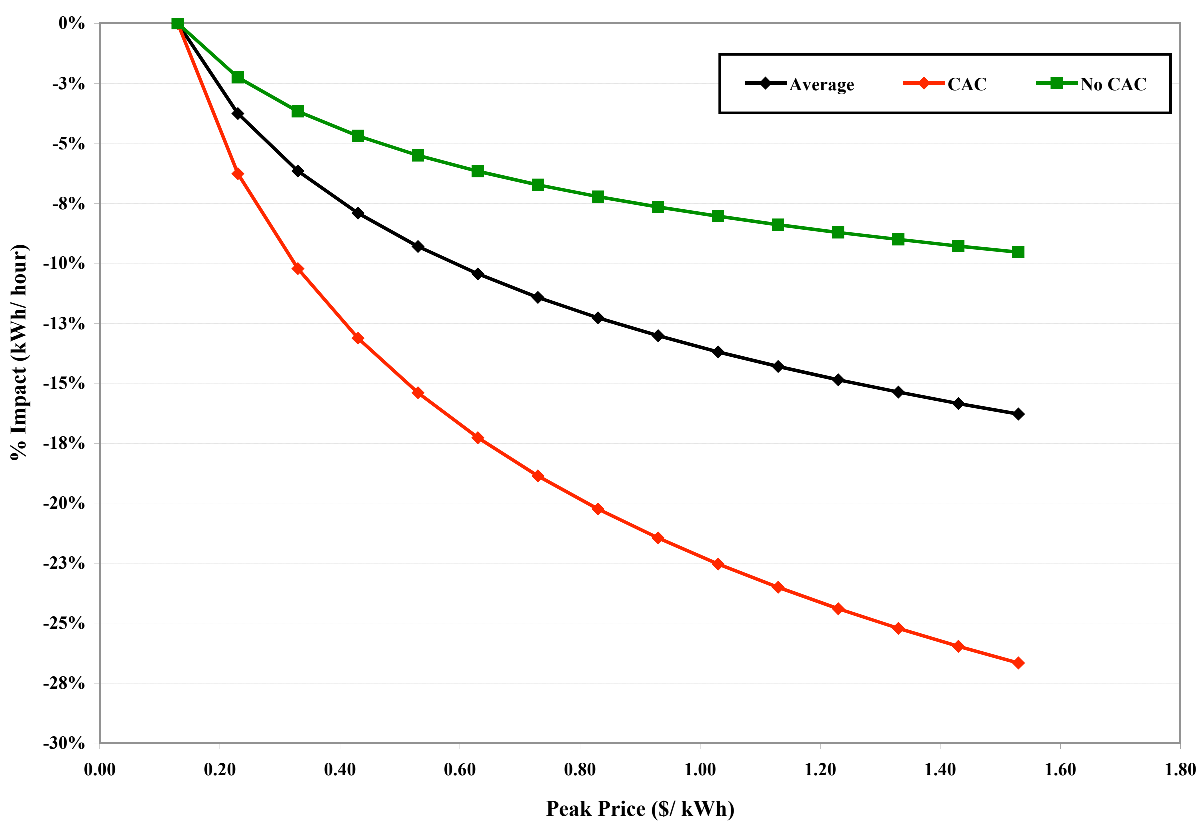
Since we would like to determine how the usage impacts vary as the critical prices are increased gradually, we have run the PRISM model using a set of prices shown in Table 32. To clarify how PRISM models the relationship between the prices and the percentage impact on load in a non-linear fashion, consider the following example. For the average customer, peak period energy usage decreases by 4% when the peak-price increases from \$0.13 per kWh to \$0.23 per kWh. However, peak period energy usage decreases by only 8% when the peak price is increased from \$0.13 per kWh to \$0.43 per kWh. This example demonstrates that the load impact increases by one-fold (rather than two-fold) when the price increases by two-fold. We can also observe the differences between customer types in their price-responsiveness from these response curves. For a given price increase, Non-CAC customers (without CAC ownership) are the least responsive group while CAC customers (with CAC Ownership) are the most responsive.

[50] For model description, see Charles River Associates (2005) and Faruqui-Wood (2008). The model can be downloaded from www.eei.org/ami.

Table 32- PRISM Impact Simulation

	% Reduction in Quantity		
Critical Price (cents/kWh)	Average Customer	Customer w/ CAC	Customer w/o CAC
0.13	0.0%	0.0%	0.0%
0.23	-3.8%	-6.3%	-2.3%
0.33	-6.2%	-10.2%	-3.7%
0.43	-7.9%	-13.1%	-4.7%
0.53	-9.3%	-15.4%	-5.5%
0.63	-10.4%	-17.3%	-6.2%
0.73	-11.4%	-18.9%	-6.7%
0.83	-12.3%	-20.2%	-7.2%
0.93	-13.0%	-21.5%	-7.7%
1.03	-13.7%	-22.5%	-8.0%
1.13	-14.3%	-23.5%	-8.4%
1.23	-14.9%	-24.4%	-8.7%
1.33	-15.4%	-25.2%	-9.0%
1.43	-15.8%	-26.0%	-9.3%
1.53	-16.3%	-26.7%	-9.5%

Figure 2- Residential Demand Response Curves on Critical Days



The response curves in Figure 2 demonstrate how the percent impact on peak period energy usage varies with the peak-period price on critical days. These curves show that the percentage impact on the peak period energy usage increases as prices increase, but at a decreasing rate. This non-linear relation between usage impacts and prices is reflected in the concave shape of the response curves.

5.0 CONCLUSIONS

This article reviews the most recent empirical evidence on the effectiveness of residential dynamic pricing programs. We find that demand responses vary from modest to substantial due to a variety of factors, some of which can be controlled such as electricity prices and whether no not enabling technologies are present, and some of which cannot be controlled, such as the design of the experiment and its location. With those caveats in mind, we find that time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs lead to a drop in peak demand of 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range.

There is need for further work on the empirical data. In particular, it would be useful to identify the best experiments and to pool their data, yielding a unified national model. However, even in the absence of a unified model, we can state with confidence that residential dynamic pricing designs can be very effective in reducing peak demand and lowering energy costs.

These results have important implications for the reliability and least cost operation of an electric power system facing ever increasing demand for power and surging capacity costs. Demand response programs that blend together customer education initiatives, enabling technology investments, and carefully designed time-varying rates can achieve demand impacts that can alleviate the pressure on the power system. Uncertainties involving the fuel prices and the form of a carbon pricing regime that is in the horizon emphasize the importance of the demand-side resources. Dynamic pricing regimes also incorporate some uncertainties such as the responsiveness of customers, cost of implementation and revenue impacts. However, these uncertainties can be addressed to a large extent by implementing pilot programs that can help guide the full-scale deployment of dynamic pricing rates.

Table 33- Summary of the Experimental Tariffs

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
California- Anaheim Peak Time Rebate Pricing Experiment	$0.0675/kWh $0.1102/kWh	Usage<=240kWh per month Usage>240kWh per month	**PTR/** Control group tariff **PTR/** $0.35/kWh rebate for each kWh reduction from baseline	All hours except 12a.m.- 6p.m. on CPP days 12a.m.- 6p.m. on CPP days
California- Statewide Pricing Pilot	$0.13/kWh	All hours	**TOU**/ Off-peak: $0.09/kWh **TOU**/ Peak: $0.22/kWh **CPP-F/** Off-peak: $0.09/kWh **CPP-F/** Peak: $0.22/kWh **CPP-F/** CPP: $0.59/kWh **CPP-V/** Off-peak: $0.10/kWh **CPP-V/** Peak: $0.22/kWh **CPP-V/** CPP: $0.65 /kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 p.m. to 7 p.m. weekdays when called 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 or 5 hours during 2 p.m. to 7 p.m., weekdays when called
Florida- The Gulf Power Select Program	$0.057/kWh	All hours	**RST/** Off-peak: $0.027/kWh **RST/** Peak: $0.104/kWh **RSVP/** Off-peak: $0.035/kWh **RSVP/** Mid-peak: $0.046 /kWh **RSVP/** Peak: $0.093/kWh **RSVP/** CPP: $0.29/kWh	12 a.m.-12p.m. and 9p.m.-12a.m. 12p.m.- 9p.m. 12a.m.-6a.m. and 11p.m.-12a.m. 6a.m.-11a.m. and 8p.m.-11p.m. 11a.m.-8p.m. Assigned hours on CPP days
Idaho- Idaho Residential Pilot Program	$0.054/kWh $0.061/kWh	Usage<= 300 kWh per month Usage>300 kWh per month	**TOU**/ Off-peak: $0.045/kWh **TOU**/ Mid-peak: $0.061 /kWh **TOU**/ On-peak: $ 0.083/kWh **CPP/** Non-CPP hours: $0.054/kWh **CPP/** CPP: $0.20/kWh	9p.m. to 7a.m. weekdays, all day on weekends 7a.m. to 1p.m. weekdays 1p.m. to 9p.m. weekdays All hours except CPP hours 5 p.m. to 9 p.m. on CPP days
Missouri- AmerenUE Residential TOU Pilot Study	-	-	**TOU**/ Off-peak: $0.048/kWh **TOU**/ Mid-peak: $0.075/kWh **TOU**/ On-peak: $0.1831/kWh **CPP/** same as TOU except that there is a CPP component set at $0.30/kWh and peak price is decreased to $0.1675 /kWh	10p.m.–10a.m. weekdays, all day on weekends 10a.m.– 3p.m. and 7p.m.-10p.m. weekdays 3p.m. – 7p.m. weekdays CPP days when called, otherwise same as TOU

Table 33- (Cont'd) Summary of the Experimental Tariffs from the Studies Reviewed

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
New Jersey- GPU Pilot	$0.12/kWh $0.153/kWh	Usage<=600kWh Usage>600kWh	**High-rate Design** **CPP/** Off-peak: $0.065/kWh **CPP/** Shoulder:$0.175/kWh **CPP/** Peak:$0.30/kWh **CPP/** Critical:$0.50/kWh **Low-rate Design** **CPP/** Off-peak:$0.09/kWh **CPP/** Shoulder:$0.125/kWh **CPP/** Peak:$0.25/kWh **CPP/** Critical:$0.50/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period 1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period
New Jersey- PSE&G Residential Pilot Program	$0.087/kWh	All hours	**CPP/** Night: $0.037/kWh **CPP/** Peak: $0.24/kWh **CPP/** CPP: $1.46/kWh	10 p.m.-9a.m. daily 1p.m.-6p.m. weekdays 1p.m.-6p.m. weekdays when called
Ontario/ Canada- Ontario Energy Board Smart Price Pilot	$0.058/kWh $0.067/kWh	Usage<= 600 kWh per month Usage>600 kWh per month	**TOU**/ Off-peak: $0.035/kWh **TOU**/ Mid-peak: $0.075/kWh **TOU**/ On-peak: $0.105/kWh **CPP/** same as TOU except that there is a CPP component set at $0.30/kWh and off-peak price is decreased to $0.031/kWh **PTR/** same as TOU with PTR at $0.30/kWh for each kWh reduction from the baseline	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays 7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays 11 a.m.- 5 p.m. weekdays CPP days when called, otherwise same as TOU CPP days when called, otherwise same as TOU
Washington - Olympic Peninsula Project	-	-	**Summer** **CPP/** Off-peak:$0.05/kWh **CPP/** On-peak:$0.135/kWh **CPP/** Critical:$0.35/kWh **Fall/ Spring/ Winter** **CPP/** Off-peak:$0.04119/kWh **CPP/** On-peak:$0.1215/kWh **CPP/** Critical:$0.35/kWh **Fixed Price/** All hours:$0.081/kWh	 9 am-6pm and 9pm-6am 6am-9am and 6pm-9pm When called 9am-3pm 3pm-9pm When called All hours

Table 34- Summary of the Experimental Elasticities

Pilot	Program	Substitution Elasticity	Own Price Elasticity	Cross Price Elasticity
New Jersey- PSE&G Residential Pilot Program	CPP w/ CAC	0.069	-	-
	CPP w/o CAC	0.063	-	-
	CPP w/ Tech.	0.125	-	-
Illinois- The Community Energy Cooperative's Energy-Smart Pricing Plan	RTP	-	-0.047 (Overall)	-
	RTP	-	-0.069 (Overall with AC cycling)	-
	RTP	-	-0.015 (Daytime)	-
	RTP	-	-0.026 (Late daytime/evening)	-
	RTP	-	-0.02 (Daytime+high price notification)	-
	RTP	-	-0.048 (Late daytime/evening+high price notification)	-
New South Wales/ Australia- Energy Australia's Network Tariff Reform	TOU	-	-0.30 to -0.38	-0.07 (Peak to shoulder)
	TOU	-	-	-0.04 (Peak to off-peak)
California- Statewide Pricing Pilot	CPP-F	0.087	-0.054 (daily)	-
	CPP-V/ Track A	0.111	-0.027 (daily)	-
	CPP-V/ Track A	-	-0.043 (weekend daily)	-
	CPP-V/ Track C	0.154 (*)	-0.044 (daily)	-
	CPP-V/ Track C	-	-0.041 (weekend daily)	-
New Jersey- GPU Pilot		**1st Month**		
	CPP w/ Tech.	0.306 (Overall)	-	-
	CPP w/ Tech.	0.155, 0.166 (Peak-shoulder)	-	-
	CPP w/ Tech.	0.395, 0.356 (Peak-off-peak)	-	-
	CPP w/ Tech.	0.191, 0.187 (Shoulder-off-peak)	-	-
		2nd Month		
	CPP w/ Tech.	0.295 (Overall)	-	-
	CPP w/ Tech.	0.055, 0.06 (Peak-shoulder)	-	-
	CPP w/ Tech.	0.407, 0.366 (Peak-off-peak)	-	-
	CPP w/ Tech.	0.178, 0.176 (Shoulder-off-peak)	-	-

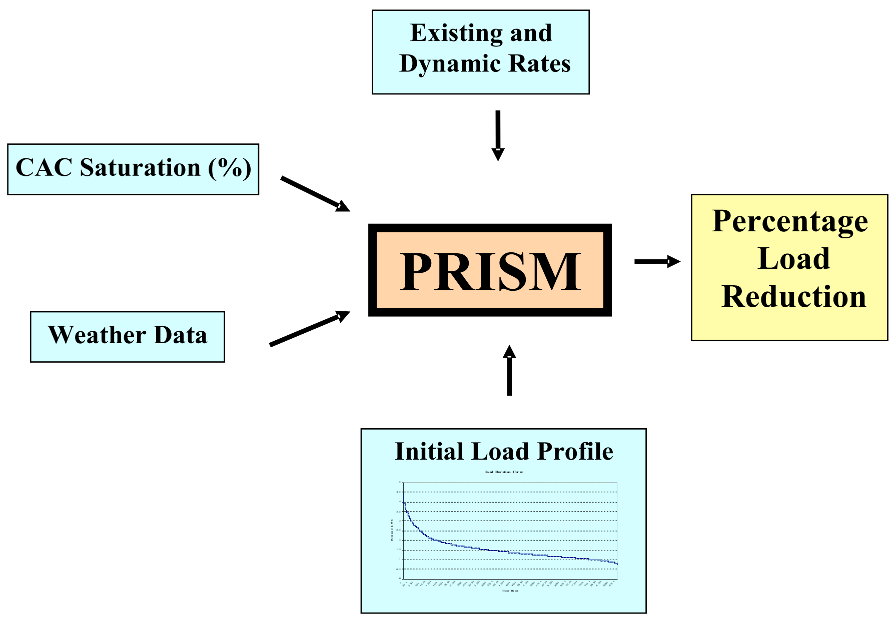
(*) Elasticity of substitution for CPP-Track C customers is estimated to be 0.077 and excludes the impact of technology (0.214). We calculated substitution elasticity including the impact of technology as 0.154 through simulation.

APPENDIX- A Primer on PRISM

The Pricing Impact Simulation Model (PRISM) was originally developed using data derived from the California Statewide Pricing Pilot (SPP) that included some 2,500 residential and small and medium sized commercial and industrial customers during 2003-2005.[51] Although it originated in California, the basic model has now been adapted to conditions in other parts of North America and the national version of PRISM is available for use by interested parties.

The PRISM includes a model for estimating "demand response impacts" and another model for estimating "financial benefits" to customers and utilities. Figure A-1 shows the PRISM Impacts Model, which is used to estimate the "unit impact" or change in consumption per customer resulting from dynamic pricing. This is the customer level demand response or the "impact" estimate.

Figure A-1: PRISM Impacts Model- Inputs and Outputs



Default demand curves and price elasticities in PRISM are based on a large data set that includes responses of approximately 2,500 customers over a two-year period to various forms of dynamic pricing, a wide variety of weather conditions, and a range of socio-demographic factors. Specifically, the data set used to estimate the customer demand curves and price elasticities in PRISM is based on a rigorous experimental design. Nevertheless, these elasticity estimates can easily be replaced with other elasticity values that a utility has estimated using data on its own customers or by other values that the utility has borrowed from other utilities.

The purpose of the PRISM Impacts Model is to estimate the change in consumption per customer resulting from dynamic pricing. In addition to estimating the impact for the average residential customer, PRISM estimates impacts for three subsets of residential customers based on the presence

[51] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 16, 2005.

of central air conditioning (CAC): CAC with no enabling technology (such as a price-sensitive thermostat or direct load control switch), CAC with an enabling technology, and no CAC.

The PRISM Impacts Model consists of four worksheets. The purpose of each worksheet is described below.

1. PRISM Impacts Inputs
All user-defined inputs to the model are entered into the PRISM Impacts Inputs worksheet. In the All-in Rate table, the user enters both the current rate and the dynamic pricing rate that is being analyzed. These rates are entered as all-in rates. In other words, they incorporate generation charges, any other variable charges, and any fixed charges on a $/kWh basis. Default version of the model is set up to accept load shapes for the average residential customer, the average customer with central air conditioning (CAC), and the average customer without CAC for a hypothetical LSE. These could be replaced with other residential customer types. In the CAC Saturation table, the user enters the CAC saturation for the region. In the Weather Data table, the user enters the weather conditions for the region of interest. The weather conditions are based on cooling degree-hours data.

2. Elasticity Estimates
The inputs from the PRISM Impacts Inputs worksheet are used in the Elasticity Estimates worksheet. This worksheet contains the PRISM model coefficients that were estimated from the data obtained during the California Statewide Pricing Pilot (SPP). The model coefficients, when combined with the input parameters, produce elasticity estimates by customer type and day type. These coefficients can be easily replaced with some other coefficients if a utility has estimated its own price responsiveness model or chooses to borrow the coefficients from some other utilities.

3. Impacts-per-Participant
The Impacts per Participant worksheet reads in each customer type's load shape and rate and, using the elasticities calculated in the Elasticity Estimates worksheet, calculates the average kWh-per-hour reduction for each period (i.e., peak period during critical days, off-peak period during non-critical days, etc). This is also represented as the percent reduction in demand during each period.

4. Impact Summary
The Impact Summary worksheet simply summarizes the output that is calculated in the Impacts-per-Participant worksheet. Table A-1 provides an example of the results summary worksheet assuming a critical peak price of $1.30 per kWh, a peak price of $0.14 per kWh, and an off-peak price of $0.083 per kWh. This worksheet provides two impacts: the change in consumption in the peak and off-peak periods by day type in terms of kWh per hour, and percentage change from the original load. These results show that the change in consumption during critical peak hours for the average residential customer is a reduction of 24 percent.

Table A-1 Example Output from PRISM Impact Summary Worksheet

Change in Consumption, by Customer Type (kWh per Hour)

	Residential			
	Average	**CAC**	**No CAC**	**CAC + Tech**
Critical Days - Peak	-0.65	-0.81	-0.20	-1.06
Critical Days - Off-Peak	0.09	0.10	0.05	0.13
Non-Critical Days - Peak	-0.04	-0.05	-0.01	-0.07
Non-Critical Days - Off-Peak	0.04	0.05	0.01	0.07

Change in Consumption, by Customer Type (% of Original Load)

	Residential			
	Average	**CAC**	**No CAC**	**CAC + Tech**
Critical Days - Peak	-24.2%	-28.4%	-10.6%	-36.9%
Critical Days - Off-Peak	4.7%	4.8%	4.0%	6.2%
Non-Critical Days - Peak	-2.6%	-3.1%	-1.3%	-4.0%
Non-Critical Days - Off-Peak	3.1%	3.7%	1.2%	4.9%

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