J Regul Econ (2010) 38:193–225
DOI 10.1007/s11149-010-9127-y

REVIEW ARTICLE

Household response to dynamic pricing of electricity: a survey of 15 experiments

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Received: 10 January 2009 / Accepted: 6 August 2010 / Published online: 31 August 2010

Abstract 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 change out 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% 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, this paper surveys the evidence from the 15 most recent pilots, experiments and full-scale implementations of dynamic pricing of electricity. It finds conclusive evidence that households 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. In addition, the design of the studies, the tools used to analyze the data and the geography of the assessment influence demand response. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between 3 and 6% and critical-peak pricing (CPP) tariffs induce a drop in peak demand that ranges

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between 13 and 20%. When accompanied with enabling technologies, the latter set of tariffs lead to a reduction in peak demand in the 27–44% range.

Keywords Dynamic pricing · Price elasticity · Elasticity of substitution · Demand models · Demand response · Rate design

JEL Classification L51 · L94 · D00

1 Introduction

For the past century, electricity pricing has not reflected the time-variation in costs that characterizes the industry. This 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. There is a consensus among economists that such a shift in the pricing paradigm toward time-varying rates would raise welfare.

For many years, the problem was the cost of installing the appropriate metering infrastructure. With digitization, costs have fallen and many States are examining the economics of upgrading the infrastructure. However, in most cases, the operational savings in distribution automation only cover roughly half of the total investment. The remainder has to be covered through demand response.

To effectuate demand response, some type of dynamic pricing will have to be instituted (Wellinghoff and Morenoff 2007). At the center of the debate is a two-part question: *Will customers respond to higher prices by lowering peak demand and if so, by how much?* That question forms the focus of this paper.

In Sect. 2, the paper provides 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. The paper tabulates the design characteristics of these 15 assessments and reviews in detail the design of each individual assessment and presents its results. In this section, our paper also compares the results across experiments and illustrates 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 Sect. 3, the paper concludes.

2 The 15 experiments

In the late 1970s and early 1980s, the first wave of experiments with time-varying pricing 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 (Faruqui and Malko 1983). 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) (Caves et al. 1984).

The results of the EPRI study 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.

However, despite the conclusive findings from the EPRI study, time-varying rates were not widely accepted across the country.[1] Most customers did not even know such rates existed for a long time. Almost two decades later, California's energy crisis rekindled interest in time-varying rates and set off the second wave of electricity pricing experiments. However, there were noticeable differences between the rate designs tested in the first and second waves of the pricing experiments. In the second wave, 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 1% of the hours of the year where somewhere between 9 and 17% of the annual peak demand is concentrated. It is very expensive to serve power during these critical periods and even modest reductions in demand can be very cost-effective.

In this section, the paper profiles 15 experiments from the second wave by presenting their salient design features, estimated impacts and, wherever they were provided, the peak/off-peak substitution and daily price elasticities. It is important to note that these pricing experiments are largely heterogeneous in their designs and the variation in their experimental quality limits the derivation of a consistent perspective. However, it describes each experiment in sufficient detail so that readers can place the results in perspective.

The study designs are presented in Table 1. Most of them are based on panel data, involving repeated measurements on a cross-section of customers. Most 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 (Shadish et al. 2002). The better designs feature measurement during the pre-treatment period which allows any potential self-selection bias to be detected. This 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 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.

[1] 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.

Table 1 Overview of the studies

No.	State/Province	Experiment	Utility	Year	Involved a control group?	Number of customers	Number of rates tested	Link to Fig. 1
1.	California	Anaheim Critical Peak Pricing Experiment	Anaheim Public Utilities (APU)	2005	Yes	52 Control, 71 treatment	1	Anaheim
2.	California	California Automated Demand Response System Pilot (ADRS)	Pacific Gas & Electric (PG&E), SCE and San Diego Gas & Electric (SDG&E)	2004–2005	Yes	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), SCE and San Diego Gas & Electric (SDG&E)	2003–2004	Yes	2,500 Customers	3	SPP, SPP-A, SPP-C
4.	Colorado	Xcel Experimental Residential Price Response Pilot Program	Xcel Energy	2006–2007	Yes	1,350 Control, 2,349 treatment	3	XCEL-TOU, XCEL-CPP, XCEL-CTOU
5.	Florida	The Gulf Power Select Program	Gulf Power	2000–2001	Yes	2,300 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	Yes	TOD Program—420 control, 85 treatment EW Program—355 control, 68 treatment	2	Idaho

Table 1 continued

No.	State/Province	Experiment	Utility	Year	Involved a control group?	Number of customers	Number of rates tested	Link to Fig. 1
8.	Illinois	The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)	Commonwealth Edison	2003–2005	Yes	1,500 Customers	2	ESPP
9.	Missouri	AmerenUE Residential TOU Pilot Study	AmerenUE	2004–2005	Yes	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	Yes	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	Yes	450 Control, 836 treatment	1	PSE&G
12.	New South Wales (Australia)	Energy Australia's Network Tariff Reform	Energy Australia	2005	Yes	TOU program: 50,000 customers SPS: 1,300 treatment	Tested several dynamic tariffs	Australia
13.	Ontario (Canada)	Ontario Energy Board Smart Price Pilot	Hydro Ottawa	2006–2007	Yes	125 Control, 373 treatment	3	Ontario-1, Ontario-2

Table 1 continued

No.	State/Province	Experiment	Utility	Year	Involved a control group?	Number of customers	Number of rates tested	Link to Fig. 1
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	Yes	28 Control, 84 treatment	3	Olympic P.

Table 2 Anaheim PTR rate design

Group	Charge	Applicable period
Control	Standard increasing-block residential tariff: \$0.0675/kWh if consumption $\leq$240 kWh per month \$0.1102/kWh if consumption >240 kWh per month	All hours
Treatment	Standard increasing-block residential tariff	All hours 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

2.1 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 (Wolak 2006). 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.

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% 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.

2.2 California: Automated Demand Response System pilot

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 (SPP) which is discussed in 2.3 (Rocky Mountain Institute 2006). 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.–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. In 2004, the peak reductions were as high as 51% on event days when participants faced a critical-peak pricing (CPP) rate and 32% on non-event days when participants faced a TOU rate. These impacts were respectively 43 and 27% in 2005, the second year of the program. 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.

2.3 California: Statewide Pricing Pilot

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 SPP that ran from July 2003 to December 2004 to test the impact of several time-varying rates (Charles River Associates 2005; Faruqui and George 2005; Herter 2007; Herter et al. 2007). 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.

2.3.1 CPP-F impacts

The average price for customers on the standard rate was about \$0.13/kWh. Under the CPP-F rate, the average peak-period price on critical days was roughly \$0.59/kWh, the peak price on non-critical days was \$0.22/kWh, and the average off-peak price was \$0.09/kWh.

The impact evaluation of the CPP-F rate revealed that on critical days, statewide average reduction in peak-period energy use was 13.1%. Impacts varied across the four climate zones which spanned a climate as diverse as that of San Francisco and Palm Springs ranged from a low of 7.6% to a high of 15.8%. The impacts also varied between the inner summer months of July, August and September and the outer summer months of May, June and October. The average peak-period impact on critical days during the inner summer months (July–September) was estimated to be 14.4% while the same impact was 8.1% during the outer summer months (May, June, and

Table 3 Residential CPP-F rate impacts on critical days for inner summer months (July–September)

Year	Start value (kWh/h)	Impact (kWh/h)	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	–

October). CPP-F rate customers also reduced their demand on normal weekdays, when just the TOU rate was in effect. On these days, the average impact was 4.7%, with a range across climate zones from 2.2 to 6.5%. However, there was no change in total energy use across the entire year was found based on the average SPP prices. When the impact of different customer characteristics on energy use by rate period was also examined, central air conditioning ownership and college education emerged as two customer characteristics that were associated with the largest reduction in energy use on critical days (Table 3).

2.3.2 TOU impacts

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

TOU customers reduced their peak period usage by 5.9% during the inner summer months of 2003. 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 were found to serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates.

2.3.3 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/kWh. Under the CPP-V rate, the

Table 4 Residential CPP-V rate impacts for summer for all customers

	Start value (kWh/h)	Impact (kWh/h)	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	–
Tech. impact—substitution	–	–	0.214	24.04	–
Daily	–	–	−0.044	−3.49	–
Tech. 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

average peak-period price on critical days was roughly \$0.65/kWh and the average off-peak price was \$0.10/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 4, Track A customers reduced their peak-period energy use on critical days by about 16% (about 25% higher than the CPP-F rate impact). Track C customers reduced their peak-period use on critical days by about 27%. A comparison of the CPP-F and the CPP-V results reveals that usage impacts are significantly larger with an enabling technology than without it.

2.4 Colorado: Xcel Energy TOU pilot

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 (Energy Insights Inc 2008a,b). The effective treatment period lasted about a year, from July 15, 2006 to July 15, 2007. Approximately 3,700 residential customers initially volunteered into the pilot program. Approximately 26% of those customers left the pilot by the end, leaving a final sample of about 2,900 participants.[2] 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. Under the first option, time-of-use (RTOU) rates, the prices were higher price during on-peak periods and lower during off-peak periods. The second rate option was Critical peak (RCPP) where the critical peak prices were in effect up to 10 summer days and lower off-peak prices applied at all other times. Customers were notified of the critical peak days by 4 p.m. the day before. The third option was time-of-use plus critical peak pricing (RCTOU) which had 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 5 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.[3] 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.

Xcel Energy notes in the conclusion to its report that the pilot was conducted as a proof of concept rather than a technology test (Energy Insights Inc 2008b). While the demand reduction was significant, the meters implemented in the pilot were too expensive to make the offerings cost-effective.

2.5 Florida: the Gulf Power select program

In 2000, Gulf Power, a subsidiary of the Southern Company, started a unique demand response program that provides customers with three different service options (Borenstein et al. 2002; Levy et al. 2002). 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

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

[3] As defined above, the summer months of the pilot included June–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.

Table 5 Demand response impacts

Rate	Enabling technology	Central AC	Critical peak (%)	On-peak (%)	Off-peak (%)
TOU	None	No	–	−10.6	−3.0
TOU	None	Yes	–	−5.2	−0.3
CPP	None	No	−31.9		−0.1
CPP	None	Yes	−38.4		0.6
CPP	AC switch	Yes	−44.8		1.3
CTOU	None	No	−15.1	−2.5	8.7
CTOU	None	Yes	−28.8	−8.2	3.6
CTOU	AC switch	Yes	−46.9	−10.6	4.0
CTOU	PCT	Yes	−54.2	−10.3	3.0

Table 6 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

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 unlike the other experiments surveyed in this paper, it charges the participants a monthly participation fee. By the end of 2001, approximately 2,300 homes were served by the RSVP. Table 6 shows the rates under the Gulf Power demand response program.

Gulf Power reports the base coincident peak demand as 6.1 KW per household (hh). RSVP program performance results presented in Table 7 show that program participants reduce their demand by 2.75 KW per household during the critical peak period or a 41% reduction in energy usage during the critical peak period.

2.6 France: Électricité de France (EDF) tempo program

Électricité de France (EDF) initiated the Tempo program in 1996 (Giraud 2004; Giraud and Aubin 1994; Aubin et al. 1995). This is a full-scale voluntary program and is not a

Table 7 RSVP program performance by period

Impact type	Period	Impact
Average demand reduction	Peak	2.1 kW/hh
	Critical peak	2.75 kW/hh
Average energy reduction	Peak	22%
	Critical peak	41%

Table 8 Rate design for the time-of-day pilot

Period	Charge	Applicable
On-peak	\$0.083/kWh	Weekdays from 1 p.m. to 9 p.m.
Mid-peak	\$0.061/kWh	Weekdays from 7 a.m. to 1 p.m.
Off-peak	\$0.045/kWh	Weekdays from 9 p.m. to 7 a.m. and all hours on weekends and holidays

controlled experiment. The rate design entails two pricing periods, peak and off-peak and three day types. The peak period is 16 h long, from 6 a.m. to 10 p.m., and the off-peak period is 8 h 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, and the red days are the most expensive 22 days.

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.[4]

2.7 Idaho: Idaho residential pilot program

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) (Idaho Power Company 2006).

2.7.1 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 8. The TOD pilot included 85 treatment and 420 control group customers as of August 2006.

[4] 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 −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.

Table 9 Energy watch day: load reductions (kW) on each of the 10 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
5 p.m.	6 p.m.	0.64	1.31	1.09	1.39	1.2	1.33	1.58	1.14	0.83	1.02	1.17
6 p.m.	7 p.m.	0.69	1.5	1.17	1.43	1.32	1.45	1.62	1.27	1.14	1.15	1.29
7 p.m.	8 p.m.	0.77	1.58	1.16	1.57	1.41	1.55	1.7	1.24	1.02	0.96	1.33
8 p.m.	9 p.m.	0.8	1.48	1.11	1.47	1.27	1.4	1.6	1.13	0.95	0.89	1.25
4-H 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

The results from the TOD pilot for the summer of 2006 revealed that, on average, the peak period percentage of total summer usage was the same for the treatment and control groups—about 22%. 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.

2.7.2 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 9 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.

2.8 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 U.S. 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/kWh (in 2006, the notification threshold was set to above \$0.13/kWh), and a price cap of \$0.50/kWh for participants meaning that the maximum hourly price is set at \$0.50/kWh during their participation in the program. In 2005, cycling switches for central air conditioners were installed at participants homes, which effectively reduced energy consumption by AC units during high price periods. This practice was continued in 2006. Additionally, in that year the Energy PriceLight, a glass orb similar in design to the Energy Orb used by some other utilities, was distributed to customers. The Energy PriceLight receives wireless price information and relays this information, i.e. high or low electricity prices, by glowing in different colors.

2.8.1 Pilot program results for 2005

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy consumption (Summit Blue Consulting 2006). 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.

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% 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 ranged from −0.02 (daytime) to −0.05 (evening and high price notification periods)

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 3–4% 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.

2.8.2 Pilot program results for 2006

Results from the analysis of the ESPP in 2006 supported the findings of program's previous years (Summit Blue Consulting 2007). The price elasticity during the summer of 2006, for hours when the price of electricity was equal to or below \$0.13/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/kWh, was estimated to be −0.082.

Table 10 Residential TOU experiment summer rate design

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

Table 11 Experiment sample design

Treatment	Treatment sample size	Control sample size
TOU	88	89
TOU-CPP	85	89
TOU-CPP-Tech	77	117
Total	250	295

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 26.7 kWh less per month total. This translates to approximately 3% 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.

2.9 Missouri: AmerenUE critical peak pricing pilot

2.9.1 First year of the pilot program (2004)

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 (RLW Analytics 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 10 shows the pilot rates.

Table 11 shows the number of participants in the treatment and control groups by rate type.

Summer 2004 results show 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, but these differences were not statistically significant. On the critical event days, the TOU-CPP and TOU-CPP-Tech groups respectively reduced their average CPP period loads by 12 and 35%, compared to the control group. Both impacts are statistically significant at the 5% level.

2.9.2 Second year of the pilot program (2005)

During the second year of the pilot, the first year rate design was maintained (Voytas 2006). In the summer of 2005, the load shifting impacts were once again insignificant for the TOU and TOU-CPP treatments on the non-event days. However, the TOU-CPP and TOU-CPP-Tech customers reduced their CPP period usages by 13 and 24% respectively on the event days similar to those in the summer of 2004. These reductions were statistically significant.

2.10 New Jersey: GPU pilot

GPU offered a residential TOU pilot program with a critical peak price and enabling technology component in the summer of 1997 (Braithwait 2000). 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 12 shows the control and treatment group rate designs.

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% 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% 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% reduction compared to the 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

Table 12 Experimental rate design

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

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.

The data were also used to estimate the elasticity of substitution using two alternative models: the constant elasticity of substitution (CES) model discussed later in this paper and the more flexible generalized Leontief (GL) model. The substitution elasticity from the CES model was estimated to be 0.30.[5] 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.

2.11 New Jersey: PSE&G residential pilot program

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007 (PSE&G and Summit Blue Consulting 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

[5] Information on the statistical significance of these estimates was not available to the authors.

Table 13 TOU/CPP rate design: summer months (June–September 2006 and 2007)

Period	Charge (June–September 2006)	Charge (June–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)

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.[6] 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 13.

PSE&G called two CPP events in Summer 2006 and five CPP events in Summer 2007. The results show that *myPower Connection* customers reduced their peak demand by 21% due to TOU-only pricing. These customers reduced their peak load by an additional 26% on CPP event days.*myPower Sense* customers with central air conditioning (CAC) ownership reduced their peak demand by 3% on TOU-only days. On CPP event days, their peak load reductions reached 17%. Interestingly, *myPower Sense* customers without CAC ownership achieved 6% peak reductions on TOU-only days while the reductions reached 20% on CPP event days. As expected,*myPower Connection* customers reduced their peak-demand consistently more than *myPower Sense* customers because they had the PCT enabling technology.

The study also estimated summer substitution elasticities for *myPower Connection and myPower Sense* customers. Table 14 presents the elasticity estimates and the associated lower and upper bounds for 95% confidence level. As expected, *myPower Connection* customers have the largest elasticity of substitution, followed respectively by *myPower Sense* customers with and without CAC ownership.

[6] 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 14 Estimated substitution elasticity for summers 2006 and 2007

Impact estimate	Substitution elasticity	95% Confidence interval
myPower connection	0.125	0.12–0.131
myPower sense with CAC	0.069	0.063–0.075
myPower sense without CAC	0.063	0.055–0.072

2.12 New South Wales/Australia: energy Australia's network tariff reform

The TOU pricing program is the largest demand management project by Energy Australia (Colebourn 2006). In 2006, the TOU results showed that residential customers displayed modest amounts of energy conservation. These conservation effects were larger in the winter than in the summer for the residential customers. Business customers were not found to be price-responsive.

Energy Australia also started the Strategic Pricing Study in 2005 which included 1,300 voluntary customers (50% business, 50% residential customers). The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and 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 showed that the residential customers reduced their dynamic peak consumption by roughly 24% for DPP high rates (A$2+/kWh) and roughly 20% 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.

2.13 Ontario/Canada: Ontario Energy Board's Smart Price Pilot

The Ontario Energy Board operated the residential Ontario Smart Price Pilot (OSPP) between August 2006 and March 2007 (Ontario Energy Board 2007). The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures. The first option was the existing Regulated Price Plan (RPP) TOU in which the off-peak rates were set at C$0.035/kWh, mid-peak rates were set at C$0.075/kWh, and on-peak rates were set at C$0.105/kWh. The second option was RPP TOU rates with a CPP component (TOU CPP) in which the CPP was set at C$0.30/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)/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. The last option was RPP TOU rates with a critical peak rebate (TOU CPR). This rate provided participants with a C$0.30/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%.

A total of 373 customers participated in the pilot: 124 in the TOU-only, 124 in the TOU-CPP, and 125 in the TOU-CPR group. 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 and 25.4%.[7] They also showed that the load shift during the entire peak period of the four summer CPP events ranged between 2.4 and 11.9%. This study also analyzed the total conservation impact during the full pilot period. The average conservation impact across all customers was estimated to be 6%.

2.14 Washington (Seattle Suburbs): Puget sound energy (PSE)'s TOU program

Puget sound energy initiated a TOU program for its residential and small commercial customers in 2001 (Faruqui and George 2003). 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% higher than the average price that prevailed before the program and the off-peak price was 15% 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% of the customers paid an extra $0.80 (the total of $0.20 power savings and $1 m 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% 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 5% 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.

2.15 Washington: The Olympic Peninsula Project

The Olympic Peninsula Project was a component of the Pacific Northwest GridWise Testbed Demonstration that took place in Washington (Pacific Northwest National Laboratory 2007). The Olympic Peninsula Project tested whether automated two-way

[7] Under the OSPP, 3–4 h of the peak period were defined as critical on a CPP day.

Table 15 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 a.m.–6 p.m. and 9 p.m.–6 a.m.
		On-peak	\$0.1215/kWh	6 a.m.–9 a.m. and 6 p.m.–9 p.m.
		Critical	\$0.35/kWh	Not called
	Summer (25 Jul–30 Sep)	Off-peak	\$0.05/kWh	9 a.m.–3 p.m.
		On-peak	\$0.135/kWh	3 p.m.–9 p.m.
		Critical	\$0.35/kWh	When called
Fixed price	All seasons	All day	\$0.081/kWh	All hours

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.

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

The fixed-price group saved 2% on their average monthly bill compared to the control group; the TOU group saved 30% and the RTP group saved 27%. Differences in average energy consumption between the contract groups were small but statistically significant.

The TOU group consumed 21% less energy and achieved conservation benefits from time-of-use pricing. The RTP group consumed as much as the control group. The fixed-price group used 4% more energy than the control group.

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 (Kiesling 2008).

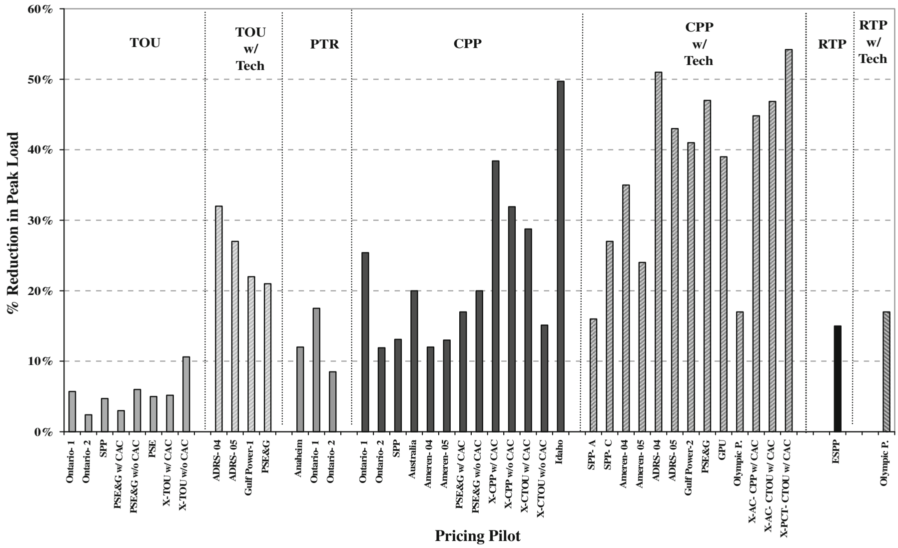

Fig. 1 Summary of the demand impacts.
Notes Percentage reduction in load is defined relative to different bases in different pilots. The following notes are intended to clarify these different definitions. 1. TOU with Technology (TOU w/Tech) and CPP with Technology (CPP w/Tech) refer to the pricing programs 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 h 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.

3 Cross-experimental assessment

The previous section's 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.

To synthesize the information from the 15 pricing experiments, a dataset of 28 observations was constructed based on results from each experimental combination

Table 16 Summary impacts

Rate design	Number of observations	Mean (%)	95% Lower bound (%)	95% Upper bound (%)	Min. (%)	Max. (%)
TOU	5	4	3	6	2	6
TOUw/Technology	4	26	21	30	21	32
PTR	3	13	8	18	9	18
CPP	8	17	13	20	12	25
CPPw/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

of rates and enabling technology. Table 16 provides the mean impact estimates and the 95% confidence intervals associated with the mean values.

On average, TOU programs are associated with a mean reduction of 4% in peak usage; the 95% confidence interval ranges from 3 to 6%. CPP programs reduce peak usage by 17% and a 95 confidence interval ranges from 13 to 20%. CPP programs supported with enabling technologies reduce peak usage by 36%; the 95 confidence interval ranges from 27 to 44%. Impacts associated with PTR and TOU supported with enabling technology programs are also provided in Table 16. However, all these results should be interpreted with caution due to the small number of observations underlying the distributions. Nine out of the 12 impact estimates with enabling technologies are tested on customers who owned central air conditioners so these impacts also capture the incremental impact arising from the ownership of these devices.

The survey finds that in addition to displaying a wide variation in the size of impacts due to different rate designs, 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.

4 Conclusions

This article reviews the most recent empirical evidence on the effectiveness of residential dynamic pricing programs. Results from 15 dynamic pricing experiments reveal that customers do respond to price. However, the magnitude of demand response induced by dynamic pricing rates varies from modest to substantial. This is likely due to the variation in prices that has been observed across the experiments and also due to the variation in enabling technologies. Additional variation may also be coming from differences in experimental design, geography and other factors that are difficult to control.

Table 17 Summary of the experimental tariffs from the studies reviewed

No.	Study	Control group tariff	Applicable period	Treatment group tariff	Applicable period
1	California—Anaheim Peak time rebate pricing experiment	\$0.0675/kWh	Usage $\leq$240 kWh per month	PTR/Control group tariff	All hours except 12 a.m.–6 p.m. on CPP days.
		\$0.1102/kWh	Usage >240 kWh per month	PTR/\$0.35/kWh rebate for each kWh reduction below baseline	12 a.m.–6 p.m. on CPP days.
2	California Automated Demand Response System Pilot (ADRS)			Same as CA SPP	
3	California Statewide Pricing Pilot (SPP)	\$0.13/kWh.	All hours	TOU/off-peak: \$0.09/kWh	12 a.m.–2 p.m. and from 7 p.m. until 12 a.m. weekdays, all day on weekends.
				TOU/peak: \$0.22/kWh	2 p.m.–7 p.m. weekdays
				CPP-F/Off-peak: \$0.09/kWh	12 a.m.–2 p.m. and from 7 p.m. until 12 a.m. weekdays, all day on weekends.
				PP-F/peak: \$0.22/kWh	2 p.m.–7 p.m. weekdays
				PP-F/ CPP: \$0.59/kWh	2 p.m.–7 p.m. weekdays when called.
				CPP-V/ Off-peak: \$0.10/kWh	12 a.m.–2 p.m. and from 7 p.m. until 12 a.m. weekdays, all day on weekends.
				CPP-V/ Peak: \$0.22/kWh	2 p.m.–7 p.m. weekdays
				CPP-V/CPP: \$0.65/kWh	2 or 5 h during 2 p.m.–7 p.m., weekdays when called.

Table 17 continued

No.	Study	Control group tariff	Applicable period	Treatment group tariff	Applicable period
4	Xcel Experimental Residential Price Response Pilot Program			NA	
5	Florida—the Gulf Power Select Program	\$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	Assigned hours on CPP days.
6	Electricite de France (EDF) Tempo Program			NA	
7	Idaho—Idaho Residential Pilot Program	\$0.054/kWh	Usage $\leq$300 kWh per month	TOU/off-peak: \$0.045/kWh	9 p.m.–7 a.m. weekdays, all day on weekends.
		\$0.061/kWh	Usage >300 kWh per month	TOU/mid-peak: \$0.061/kWh	7 a.m.–1 p.m. weekdays
				TOU/on-peak: \$0.083/kWh	1 p.m.–9 p.m. weekdays
				CPP/non-CPP hours: \$0.054/kWh	All hours except CPP hours.
				CPP/CPP: \$0.20/kWh	5 p.m.–9 p.m. on CPP days.
8	The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)			NA	
9	Missouri—AmerenUE Residential TOU Pilot Study	NA	NA	TOU/off-peak: \$0.048/kWh	10 p.m.–10 a.m. weekdays, all day on weekends.
				TOU/mid-peak: \$0.075/kWh	10 a.m.–3 p.m. and 7 p.m.–10 p.m. weekdays
				TOU/on-peak: \$0.1831/kWh	3 p.m.–7 p.m. weekdays

Table 17 continued

No.	Study	Control group tariff	Applicable period	Treatment group tariff	Applicable period
				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	CPP days when called, otherwise same as TOU.
				High-rate design	
10	New Jersey—GPU Pilot	\$0.12/kWh	Usage ≤600 kWh	CPP/off-peak: \$0.065/kWh	1 a.m.–8 a.m. and 9 p.m.–12 p.m. weekdays, all day on weekends and holidays
		\$0.153/kWh	Usage >600 kWh	CPP/Shoulder: \$0.175/kWh	9 a.m.–2 p.m. and 7 p.m.–8 p.m. weekdays
				CPP/peak: \$0.30/kWh	3 p.m.–6 p.m. weekdays
				CPP/critical: \$0.50/kWh	When called during peak period
				Low-rate design	
				CPP/off-peak: \$0.09/kWh	1 a.m.–8 a.m. and 9 p.m.–12 p.m. weekdays, all day on weekends and holidays
				CPP/shoulder: \$0.125/kWh	9 a.m.–2 p.m. and 7 p.m.–8 p.m. weekdays
				CPP/peak: \$0.25/kWh	3 p.m.–6 p.m. weekdays
				CPP/critical: \$0.50/kWh	When called during peak period
11	New Jersey—PSE&G Residential Pilot Program	\$0.087/kWh	All hours	CPP/night: \$0.037/kWh	10 p.m.–9 a.m. daily.
				CPP/peak: \$0.24/kWh	1 p.m.–6 p.m. weekdays
				CPP/CPP: \$1.46/kWh	1 p.m.–6 p.m. weekdays when called
12	Energy Australia's Network Tariff Reform			NA	

Table 17 continued

No.	Study	Control group tariff	Applicable period	Treatment group tariff	Applicable period
13	Ontario/Canada—Ontario Energy Board Smart Price Pilot	\$0.058/kWh	Usage ≤600 kWh per month	TOU/off-peak: \$0.035/kWh	10 p.m.–7 a.m. weekdays, all day on weekends and holidays
		\$0.067/kWh	Usage >600 kWh per month	TOU/mid-peak: \$0.075/kWh	7 a.m.–11 a.m. and 5 p.m.–10 p.m. weekdays
				TOU/on-peak: \$0.105/kWh	11 a.m.–5 p.m. weekdays
				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	CPP days when called, otherwise same as TOU.
				PTR/same as TOU with PTR at \$0.30/kWh for each kWh reduction below baseline	CPP days when called, otherwise same as TOU.
14	Puget Sound Energy (PSE)'s TOU Program			NA	
				Summer	
15	Washington—Olympic Peninsula Project	NA	NA	CPP/off-peak: \$0.05/kWh	9 a.m.–6 p.m. and 9 p.m.–6 a.m.
				CPP/on-peak: \$0.135/kWh	6 a.m.–9 a.m. and 6 p.m.–9 p.m.
				CPP/critical: \$0.35/kWh	Not called
				Fall/Spring/Winter	
				CPP/off-peak: \$0.04119/kWh	9 a.m.–3 p.m.
				CPP/on-peak: \$0.1215/kWh	3 p.m.–9 p.m.
				CPP/critical: \$0.35/kWh	When called
				Fixed price/all hours: \$0.081/kWh	All hours

With those caveats in mind, the paper find that time-of-use rates induce a drop in peak demand that ranges between 3 and 6% and CPP tariffs lead to a much greater drop in peak demand of 13–20%. Time-of-use impacts are lower because the peak prices they charge customers are lower than the peak prices charged during critical-peak periods by CPP rates. In large measure, the higher the price that customers face during peak periods, the greater is the amount of demand response they are likely to exhibit. However, higher prices do not induce proportionately higher responses, confirming once again that the law of diminishing returns is at work.

The paper also finds that enabling technologies substantially boost impacts. For example, when these technologies are provided along with CPP rates, the amount of demand response lies in the 27–44% range.

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 during critical periods caused by extreme weather conditions or unit outages. Uncertainties involving fuel prices and the future price of carbon emphasize the need to invest in 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.

There is need for further empirical work. In particular, it would be useful to identify the best experiments from the 15 surveyed in the paper, pool their data, and estimate a unified model of customer behavior. The model would be superior to the individual models since it would feature greater price, technology and geographical variation. It would allow better forecasts to be made of demand response once the exogenous variables have been specified and it would provide an alternative for utilities that do not want to conduct their own experiment.

In addition, it would be useful to probe further the equivalence between CPP rates and PTRs. This is not only an empirical issue. It is also a theoretical and policy issue. On first blush, PTRs represent a Pareto improvement. Customers can be no worse off than being on their standard tariff but have the opportunity to improve their economic welfare by reducing load during critical hours and earning rebates. However, someone has to pay the rebates. In certain markets, the non-responding customers would be the ones paying the rebates. In others, it could be the wholesale market operator. In addition, there is the statistical issue of measuring what the customers would have consumed in the absence of the rebate. The requirement to construct a valid counter factual is not trivial.

The paper has shown that enabling technologies boost impact. From a policy perspective, this raises the issue of who should pay for the enabling technology. Should it be the participating customer or all customers (as socialized through the utility)?

Acknowledgments The authors are economists with *The Brattle Group* located respectively in San Francisco, California and Cambridge, Massachusetts. They are grateful to the analysts whose studies are reviewed in this paper for sharing their work. They are also indebted to two anonymous referees for their comments on previous drafts. The research was funded in part by the Edison Electric Institute and the Electric Power Research Institute. The views expressed in this paper are our own and not necessarily shared by Brattle or by our research sponsors.

Appendix 1

The CES model

One of the more popular and theoretically appealing model specifications is the CES demand system. Its application to electricity pricing centers on the substitution Eq. 1. The equation expresses the peak to off-peak quantity ratio as a function of the peak to off-peak price ratio,[8] a weather term representing the difference in cooling degree hours between the peak and off-peak periods[9] and fixed effects variable for each customer.

$$\ln\left(\frac{Q_{\mathrm{p}}}{Q_{\mathrm{op}}}\right) = \alpha + \sigma \ln\left(\frac{P_{\mathrm{p}}}{P_{\mathrm{op}}}\right) + \delta(\mathrm{CDH}_{\mathrm{p}} - \mathrm{CDH}_{\mathrm{op}}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \tag{1}$$

where Q_{p} is the average energy use per hour in the peak period for the average day; Q_{op} is the average energy use per hour in the off-peak period for the average day; σ is 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} is the average price during the peak pricing period; P_{op} is the average price during the off-peak pricing period; δ is the measure of weather sensitivity; $\mathrm{CDH}_{\mathrm{p}}$ is the cooling degree hours per hour during the peak pricing period; $\mathrm{CDH}_{\mathrm{op}}$ is the cooling degree hours per hour during the off-peak pricing period; θ_i is the fixed effect coefficient for customer i; D_i is a binary variable equal to 1 for the ith customer, 0 otherwise, where there are a total of N customers; ε is the 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.

$$\ln(Q_{\mathrm{d}}) = \alpha + \eta_{\mathrm{d}} \ln(P_{\mathrm{d}}) + \delta(\mathrm{CDH}_{\mathrm{d}}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \tag{2}$$

[8] 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.

[9] 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.

where Q_{d} is the average daily energy use per hour; η_{d} is the price elasticity of demand for daily energy (defined below); P_{d} is the average daily price (e.g., a usage weighted average of the peak and off-peak prices for the day); $\mathrm{CDH_d}$ is the cooling degree hours per hour during the day; ε is the 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 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.

$$\ln\left(\frac{Q_{\mathrm{p}}}{Q_{\mathrm{op}}}\right) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \sigma \ln\left(\frac{P_{\mathrm{p}}}{P_{\mathrm{op}}}\right) + \delta(\mathrm{CDH_p} - \mathrm{CDH_{op}}) + \lambda(\mathrm{CDH_p} - \mathrm{CDH_{op}}) \ln\left(\frac{P_{\mathrm{p}}}{P_{\mathrm{op}}}\right) + \phi(\mathrm{CAC}) \ln\left(\frac{P_{\mathrm{p}}}{P_{\mathrm{op}}}\right) + \varepsilon \tag{3}$$

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

$$\mathrm{ES} = \sigma + \lambda(\mathrm{CDH_p} - \mathrm{CDH_{op}}) + \phi(\mathrm{CAC}) \tag{4}$$

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.

$$\ln(Q_{\mathrm{D}}) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \eta \ln(P_{\mathrm{D}}) + \rho(\mathrm{CDH_D}) + \chi(\mathrm{CDH_D}) \ln(P_{\mathrm{D}}) + \xi(\mathrm{CAC}) \ln(P_{\mathrm{D}}) + \varepsilon \tag{5}$$

where Q_{D} is the average daily energy use per hour; η is the daily price elasticity; P_{D} is the average daily price; ρ is the measure of weather sensitivity; χ is the change in daily price elasticity due to weather sensitivity; $\mathrm{CDH_D}$ is the average daily cooling degree hours per hour (base 72°); ξ is 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 is the fixed effect for customer i; D_i is a binary variable equal to 1 for the ith customer, 0 otherwise, where there are a total of N customers; ε is an error term.

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

$$\text{Daily} = \eta + \chi(\text{CDH}_\text{D}) + \xi(\text{CAC}) \tag{6}$$

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