Energy Policy Act 2005
PURPA Standards
Time-Based Metering and Communications

Staff Comments

Standard: Time-Based Metering and Communications

Each electric utility shall offer each of its customer classes and, provide individual customers upon customer request, a time based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others

(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

PURPA §111(d)(14)(C) goes on to direct that

> [e]ach electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

EPAct 2005 also establishes at PURPA §115(i) an "investigation requirement" that states that:

> Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.

This section of the Act generally requires that each jurisdiction begin a proceeding to consider whether or not to adopt these standards within one year of enactment and regulators are to reach a decision within two years of enactment. (There are some exceptions for jurisdictions that have already adopted or recently considered a similar standard.)

Recommendation:

TVA staff recommends the following modified standard be adopted.

> TVA will initiate a rate change in accordance with the provisions of its wholesale power contract with the distributors of TVA power to assess in detail 1) the benefits and cost of implementing a mandatory time-based rate schedule for large retail customers, under which the retail rates reflect seasonal and time-of-day variations in the costs of generating and purchasing electricity, 2) the benefits and cost of implementing advanced metering and communications technology to help the electric consumer manage energy use and cost, and 3) other factors affecting the implementation of such structures as soon as feasible.

TVA is primarily a wholesale provider of electricity, currently selling power to 158 distributors, who, in turn, resell power to roughly 4.3 million residential, commercial and industrial customers. TVA also directly serves 62 retail customers, who account for approximately 14% of TVA's total revenues.

The focus of both the standard proposed by the Energy Policy Act and of the modified standard proposed for adoption below is on potential action by TVA with regard to: (1) TVA's role as a retail provider of electricity that does not fall under the purview of any state or federal regulatory agency and (2) TVA's role as the regulator of distributors. Adopting the modified standard set forth above would encourage conservation and energy efficiency, and continued evaluation of the benefits of expanding the availability of advanced metering technologies, seasonal, time-of-day pricing, and critical peak pricing. Thus it would promote the objectives of the standard proposed by the Energy

Policy Act to the extent that the further consideration provided for in the modified standard demonstrates the feasibility of implementing such technologies and pricing.

In addition to adoption of the modified standard proposed above, the staff also recommends promoting the objectives of the standard proposed by the Energy Policy Act by focusing on potential action by TVA with regard to its role as a wholesale provider of electricity. At present, TVA generally serves its distributor wholesale customers at “flat” (non-time differentiated) rates. As a result, distributors have little incentive to promote time-differentiated rates to their retail customers because wholesale power costs are not time-differentiated. Moreover, some distributors are frustrated by their inability to lower their power costs due to the lack of time-based pricing. Therefore, we also plan to consider implementing a wholesale rate structure that more accurately reflects the cost of power which varies seasonally and by time of day, and that TVA should pursue the implementation of such a rate structure as soon as it is feasible through the rate change process.

Basis for Recommendation and Background: See attached supporting information

CONTENTS OF SUPPORTING INFORMATION

Introduction & Background

This report reviews the Public Utility Regulatory Policy Act (PURPA) Standards in the Energy Policy Act of 2005 (EPAct05) with regard to smart metering and time-based pricing and provides recommendations for TVA adoption and implementation of these standards.

The remainder of this section provides background on the ratemaking standards originally introduced by PURPA and the changes directed by the EPAct05. It also summarizes the key issues introduced by these changes as identified by a number of key industry organizations in the industry. Section II describes historical applications of time-based pricing across the industry and by TVA along with experience regarding the success of these programs. Section III discusses the potential benefits of offering time-based pricing structures. Section IV discusses issues germane to advanced metering, and, Section V introduces the Staff Recommendations.

A. Background on PURPA and Changes in EPAct05

1. The Public Utility Regulatory Policies Act of 1978

PURPA of 1978 was enacted to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. The original PURPA section 111(d) specified the following five standards concerning rate determination and design: (1) cost-of-service based rates, (2) declining block rates, (3) time-of-day rates, (4) seasonal rates, and (5) interruptible rates.

In response to this, in August 1980 the TVA Board approved a resolution to:[1]

- ❑ Affirm the development of rates based on cost of serving
- ❑ Replace declining block rates with flat rates for most commercial and industrial customers
- ❑ Support for time-of-day rates where cost-effective
- ❑ Endorse seasonal variations in rates where justified
- ❑ Continue interruptible power contracts for large customers
- ❑ Support the development and implementation of cost-effective load management techniques

[1] "Determination on Ratemaking Standards," approved by the TVA Board of Directors, April 1, 1981 minute entry 1264-11."

- Approve a voluntary program to encourage the construction of energy-saver homes

2. Changes in the Applicable Portions of EPACT05

On August 8, 2005 the President signed into law the Energy Policy Act of 2005 (EPAct 05), which added five new standards to the ten standards outlined previously in the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPAct 92). The new standards added to PURPA section 111(d) are:

Net Metering: making available upon request net metering service to any electric consumer that the electric utility serves.

Fuel Sources: ensuring that the electric energy sold to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

Fossil Fuel Generation Efficiency: developing and implementing a 10-year plan to increase the efficiency of its fossil fuel generation.

Time-Based Metering and Communication: offering time-based rate structures and the metering technology required to implement such structures.

Interconnection Service: making available, upon request, interconnection service to any electric consumer that the electric utility serves.

3. Time-Based Metering and Communication Standard

B. Issues that Arise in Considering the PURPA Standards

In Edison Electric Institute's advisory report to utilities and regulators, Kenneth Gordon et al. offer a number of policy questions that should be addressed while considering the new PURPA standards for time-based pricing and metering.[2]

- Are the existing rates sending the right price signals to customers? If not, in what ways, and to what extent, do they diverge?
- Which form(s) of time-based rate design should be used?
- What rate structure changes would be acceptable to customers?
- Should the time-based rate structure be optional?
- What are the tradeoffs that should be considered when designing time-based rate designs?

[2] Kenneth Gordon, Wayne Olson and Amparo Nieto, "Responding to EPAct 2005: Looking at Smart Meters for Electricity Time-Based Rate Structures and Net Metering," Prepared for the Edison Electric Institute, May 2006.

- Can we count on significant demand response when the efficient price is charged? What do we know about how responsive the different customer classes are to changes in the prices they face?
- How should an interruptible rate be priced?
- Will interruptible capacity be reliable enough to avoid the need for costly new generation resources? How does broad reform of the pricing structure compare to older programs, such as interruptible rates?
- How can time-based rate designs be (most effectively) implemented?
- Should customers that request a smart meter pay for the installation and other costs of that meter, or should the costs be socialized in rates?

The key theme throughout Ken Gordon's discussion is that pricing structures (and the required metering) should be put into effect that are cost based and provide positive net benefits to the utility and society at large. He advises that this will vary by utility and jurisdiction.

> [whether there are net benefits] will vary from utility to utility and state to state and each utility's circumstances should inform a commission's decision making process. Depending on the starting point of each jurisdiction with regard to its rate structure, system demand characteristics, status of restructuring, and many other concerns unique to the state, equivalent cost-benefit analyses may yield completely different results.[3]

Gordon also encourages a careful consideration of these standards because they can yield significant economic benefits.

> It is incumbent on state regulators to recall that time-based pricing issues require a careful analysis not only because the revisions in PURPA require states to consider them, but because there is a strong economic policy basis for doing so. Given the socially desirable consequences of aligning rates with costs, regulators should evaluate the extent to which time-based pricing can provide customers with the proper incentives to expand or reduce usage when it is efficient to do so.[4]

In a reference manual for implementation of the EPAct 05, sponsored by several organizations representing different industry types and regulatory interests, the following advice is provided for those jurisdictions considering the new time-based pricing and metering:[5]

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[3] Ibid, p. 10.

[4] Ibid, p 7.

[5] Kenneth Rose and Karl Meeusen, *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005*, Sponsored by American Public Power Association, Edison Electric Institute, National Association of Regulatory Utility Commissioners, and National Rural Electric Cooperative Association, March 22, 2006.

- That each type of time-based rate is different and may not work the same for all consumer sectors.
- That if one type of time-based rate does not work, it does not mean that none of them will work.
- Most of the benefits of time-based rates will be realized only if consumers respond to price signals and change their consumption patterns.
- Many of the goals of time-based rates are interconnected. Goals may work in ways that are positive, negative, or undetermined with others.
- Time-based rates may only be appropriate for certain consumer sectors or utilities in some locations and the end decision may be that time-based rates are appropriate for some sectors or utilities but not for others.

C. Activities at Neighboring States

All of the jurisdictions surrounding TVA are addressing the new PURPA standards through various regulatory processes. These activities are summarized in Appendix A.

II. Historical Application of Time-Based Pricing

A. Types of Time-Based Pricing Structures

The types of time-based pricing programs vary widely in complexity and risk tradeoffs between the customer and electricity provider. Most of the recent literature on time-based pricing separates the alternatives into four broad categories, which is probably why the new PURPA standards relied on those same categories: time of use (TOU), Critical Peak Pricing (CPP), real-time pricing (RTP) and curtailable and interruptible service (CIS).

TOU rates have different per-unit prices for usage during different blocks of time. These blocks of time could be as simple as different months of the year, such as the case with seasonally differentiated rates. The blocks could be defined as hours of the day or they could be both seasonal and daily definitions, which is referred to as a seasonal time of use rate or (STOU). With these rates either or both the energy charge and demand charge could vary by specified time period. It could also be as subtle as charging for demand on metered kW during only the on-peak period with no other differences in the basic tariff.

CPP looks very similar to the TOU structure but it includes high per-unit prices for usage during periods that are designated to be critical peak periods by the utility. Unlike TOU blocks, the days in which critical peaks occur are not designated in the tariff, but dispatched on relatively short notice (usually less than a day) as needed, for a limited number of days during the year. CPP rates can superimpose the critical peak price on other types of rates, for example on flat rates or TOU rates. The CPP design is conceptually very similar to the market day product that TVA currently offers to large commercial and industrial customers.

The prices in RTP programs vary continuously over time (usually by hour) in a way that directly reflects the wholesale price of electricity, rather than at pre-set prices as in virtually all other rate designs. Many varieties of RTP exist in the U.S. and other parts of the world.

There is also a wide range of CIS programs where customers are compensated, one way or another, for being asked to curtail their usage of electricity when system constraints or economics warrant it or for being involuntarily interrupted by the utility for the same reasons. These programs range in design across the country in terms of how customers are compensated for agreeing to participate and whether and how buy-through provisions are incorporated.

B. Implementation Issues with Time-Based Pricing

There are two basic ways to apply time-based pricing to any group of customers: mandatory change in the pricing structure for basic service or voluntary programs that allow customers to choose whether or not to participate. There is also a variation on the voluntary program where the time-based structure is set as the basic service rate and customers are given the opportunity to opt out by paying a premium. As discussed below, voluntary programs have been more widely adopted than mandatory programs. Virtually all applications of time-based pricing for residential customers are through voluntary programs.

1. Mandatory Programs

The most immediate approach for achieving the benefits described above is to implement mandatory time-based pricing (such as time-of-use pricing) for all customers. Utilities that have implemented mandatory TOU pricing have realized significant system-wide benefits.[6]

The difficulty with implementing mandatory TOU for any class of customers is that it results in immediate windfalls in the form of bill decreases for those customers whose load shapes are (already) not coincident with the system peak and immediate rate shock, in the form of bill increases for those customers that are coincident. For many customers the bill increases can be substantial leading to customer relations and communication challenges, to say the least. Consequently, time-based pricing programs such as TOU rates have not typically been mandated for residential classes.[7]

[6] Appendix B provides a bibliography of literature on the response to time-based pricing.

[7] There are a few situations where Commissions have ordered utilities to mandate TOU pricing for very large residential customers. One such example is in New York where Niagara Mohawk and other utilities were required to put all residential customers with usage greater than 30,000 kWh/year on a TOU rate.

These programs have been offered as voluntary (or pilot) programs, typically targeted to customers with high usage levels or ownership of major appliances such as central air conditioning or pool pumps. The result is that most voluntary programs have relatively few customers or, due to conditions placed on the pilots, are not truly cost based.

2. Voluntary Programs

The primary problem with implementation of voluntary time-based pricing is the revenue attrition due to self-selection bias. To explain this issue in more detail, it is useful to review how TOU schedules are developed and then to discuss the customer selection process.

Calculating appropriate TOU prices is a reasonably straight forward exercise if the rate is mandatory. In this case the TOU prices are calculated by multiplying the expected loads times the hourly generation costs for each specified time period (referred to as the load-weighted marginal cost or load-weighted market price).

However, the design process is much more problematic for a voluntary program. Usage patterns vary significantly across customers and few utilities have load research data on a customer-by-customer basis. The actual cost to supply these different types of customers will vary widely, depending on the percentage of usage that occurs in the different periods of the day. Without precise metered load data, the energy supplier will not be able to determine the costs to supply individual customers. As a result of these problems, utilities will take one of two approaches to designing a voluntary TOU program.

In one approach, the TOU prices are set to be revenue neutral to the standard tariff for the average customer in the class. In other words, the TOU prices are set to recover the same revenue as would be recovered under the standard tariff at the class-average level of usage. The problem with this approach is that the most likely customers that will subscribe to this TOU program are “instant winners” in that they see lower bills than under the standard rate, even without changing their usage pattern because their peak-period usage is less than the class average. This outcome leaves the utility with less revenue than before and is not truly revenue neutral between the standard rate and the TOU rate.

In the second approach, the TOU prices are designed to be revenue neutral for those customers that the utility expects would be most likely to subscribe to the TOU program. The TOU prices are set to recover the same revenue as under the standard tariff after accounting for the lower-cost usage patterns of the customers most likely to subscribe. With this approach, customers most likely to choose the TOU program are those with peak-period usage that is lower than those customers in the targeted group. As a result, relatively few customers are likely to choose the program, and those that do choose see lower bills leading to lower revenue to the utility. In both cases, the utility recovers less revenue and realizes lower margins although the second approach provides a more favorable outcome.

Because of the potential revenue erosion created by optional rates, and the bill impacts to customers with mandatory rates, some utilities such as Duke Power have adopted a third approach, which is to apply a rate equalization factor (REF). The REF is similar to a customer baseline load feature of many RTP programs. It is calculated as the difference between the customer's bill on the standard tariff and what the customer's bill would be under the optional TOU rate, often for the most recent 12 months of billing history. The REF is meant to make the customer revenue neutral between the two rates if the customer makes no change in usage patterns. It eliminates windfall gains and losses, and allows any customer who can respond to price to benefit from the TOU rate, regardless of how their load patterns compare to the average for the class.

One alternative approach to voluntary time-based programs is default enrollment where the utility enrolls consumers automatically (the time-based structure becomes the base rate) but gives them the ability to opt out of the program.[8] A premium could also be added to reflect the risks associated with the flat rate alternative to the basic TOU rate.

C. Application of Time-Based Pricing across The Industry

This section discusses the application of time-based programs with other electric utilities. Presented first are results from a recent industry-wide survey. This is followed with a couple of examples of the application of critical peak pricing, a current time-based application that is gaining popularity due to its ability to result in more significant demand response.

1. Industry Survey of Time-Based Programs

A number of surveys have been conducted recently on electric utility application of time-based pricing. The most comprehensive survey, in terms of identifying the range of time-based programs that have been applied, was recently completed for the U.S. Environmental Protection Agency, which provides useful information on the adoption of these programs in the U.S. and other parts of the world. TOU is the most common form of time differentiated pricing offered by utilities for residential and C&I customers, followed closely by CIS.[9] In almost all cases, the time-based structures are voluntary as opposed to mandatory programs.

Appendix B provides a number of detailed tables from the EPA report regarding the utilities that have applied these programs.[10] Included in the states surveyed are a number of neighboring utilities as summarized in the Table 1.

A more intensive survey of RTP programs was conducted recently through Laurence Berkeley Laboratory where the programs of 43 firms offering this product were

[8] Rose and Meeusen, op. cit. p. 82.

[9] Energy & Environmental Economics, *A Survey of Time-of-Use Pricing and Demand-Response Programs*, Prepared for the Environmental Protection Agency July 2006. .

[10] The tables in Appendix A are reproduced exactly as they appeared in the Energy and Environmental Economics 2006 report.

evaluated.[11] Of the 43 firms evaluated only 3 had over 100 RTP participants and 12 had zero participation. However, most of the firms evaluated indicated that they did not actively promote or educate customers about these programs.

D. Application of Time-Based Pricing by TVA

1. End-Use Wholesale Rate Schedules

TVA has offered optional time-based rates for each of the customer classifications through its end-use wholesale tariff structures. These are traditional time-of-use daily rating periods differentiated by three seasons. However, the historical participation levels for these rates have been very low. As of FY 2006, 19 distributors had only 744 customers on the voluntary TOU programs, which represent 6.9 million kWh and $16.6 million in annual revenue.

2. Voluntary Time-Based Programs for Large Industrial Customers

In addition to the time-based rates offered through the end-use wholesale structures, TVA has for many years offered its large commercial and industrial customers a diverse portfolio of time-differentiated pricing products, including a number of variations of hourly pricing. In almost all cases, these products have been linked with interruptible power service.

[11] G. Barbose, C. Goldman and B. Neenan (2004) "A Survey of Utility Experience with Real Time Pricing," Report LBNL-54238, Lawrence Berkeley National Laboratory, University of California.

TABLE 1. TOU Rates Offered C&I by Neighboring Utilities

Utility (State)	Energy Pricing	Demand Pricing	Optional Or Mandatory	Tariff Ref
Alabama Power Company (AL)	Large seasonal & daily differential	No demand charge	Optional	LPTL (Alternate)
Carolina Power & Light (NC)	Small daily TOU differential	Moderate seasonal differential with high demand charge in peak season.	Optional	LGS-TOU-8
Duke (OH)	Small daily and seasonal differential	Small seasonal differential with zero demand charge for daily off-peak periods	Optional	Standard Contract Rider No. 12.2
Duke Energy (NC)	Moderate daily TOU differential	Moderate seasonal differential with larger charge in peak season. Charge based on-peak kW	Optional	Schedule OPT (NC) – Optional Power Service TOU
Florida Power & Light (FL)	Large daily TOU differential	Flat	Optional	General Service Demand TOU
Florida Power Corp (FL)	Large daily TOU differential	Demand charge based on max kW during daily peak period	Optional	GSDT-1 Optional TOU
Georgia Power (GA)	Large STOU differential	Large seasonal and daily peak differential with higher kW charge during peak	Optional	TOU-GSD-3
Gulf Power (FL)	Flat	Demand charge based on max kW during daily peak period	Optional	GSDT Optional
Jacksonville Electric (FL)	Large daily TOU differential	Higher demand charge during peak period	Optional	GSDT

E. Success of Voluntary Time-Based Programs

The success of any TOU program is determined by the participation levels and the extent to which participating customers respond to the price signals. Although TOU programs of various types have been offered by most electric utilities across the U.S. they have never achieved widespread adoption by customers (particularly by residential customers) and the estimates of the benefit-cost tradeoff have not been favorable. Recent surveys show that an overwhelming majority of utilities offer TOU programs to residential customers yet subscription rates are less than 1%.[12] And, a number of studies on past TOU programs have found limited demand response. As mentioned above, this has also been the case with the historic offerings of time-of-use pricing for TVA's smaller customers.

In a special report to the Idaho Public Utilities Commission it is argued that this outcome is primarily the result of poor pricing design in the previous TOU programs. Traditionally designed TOU prices are commonly averages across a wide span of hours (often times as many as 12 hours for a peak period window). Hence, the difference between peak and off-peak prices is significantly reduced. The small difference leads to negligible benefits from load reduction or shifting and an overall lack of customer responsiveness.[13]

Studies of real-time pricing programs seem to confirm that higher response rates result from price spikes of shorter duration. A recent evaluation of hourly load data from industrial customers participating in a real-time pricing program at Central and Southwest reached the following conclusions:

> On balance, we find that customers differ substantially in their demand response to price, but under certain conditions, the response can be substantial. Most of the response was due to load shifting from peak to off-peak periods, rather than due to overall energy conservation. This is not unexpected because the firms were only exposed to high prices for about 10% of the year. During the rest of the year, prices were well below previous tariff levels. Moreover, even for those firms with substantial load growth during the economic expansion of the late 1990s, there was also substantial evidence the price differentials led to proportionately higher load growth during off-peak hours.
>
> Further, the response rates appear to be highest for short peak periods, and fall rather dramatically as the length of the peak increases. One explanation for this reduction in response is that a "fatigue" factor sets in and at some point in time the outage costs become so large that firms must restore electricity usage to more normal levels. However, there is also evidence that the elasticities of substitution vary directly with the differential between peak and off-peak prices. Therefore, since the longer peak periods examined have somewhat lower

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[12] Steven Braithwait and Ahmad Faruqui, *Demand Response - The Forgotten Solution to California's Energy Crisis,* Electric Power Research Institute, 2001.

[13] Braithwait, Steven, "Residential Time-of-Use Feasibility Study," Report to the Idaho Public Utilities Commission, September 12, 2002.

average price differentials, some of this apparent “fatigue” factor may be a normal reaction to smaller price differences.[14]

A similar finding was made in a study of industrial customer response to the price spikes during the summer of 1999. It was found that customers paying hourly prices would reduce load 10 percent during peak hours that averaged 20¢/kWh but would increase their response to 25% on high priced days where peak hours exceeded 35¢/kWh.[15]

These findings suggest that more significant load response occurs when customers are faced with *higher peak prices during shorter time periods*. As a result, a growing number of pricing experts are emphasizing critical peak features in time-of-use design to try to capture more of the efficiency gains that comes from passing through hourly wholesale prices.

F. Specific Examples of Critical Peak Pricing

This section provides two examples of critical peak pricing programs offered in different parts of the country: GoodCents by Gulf Power and the Pacific Gas & Electric pricing pilot.

1. GoodCents by Gulf Power

A CPP program has been offered to residential customers by Gulf Power over the past five years. In this program the customer agrees to have an interactive metering system installed in their home and is placed on the following rate schedule.

Customer Charge: $10.00
Program Participation Fee: $ 4.95

Energy Charges:

<u>May – October</u>	
Weekdays	
11 p.m. – 6 a.m.	1.785¢
6 a.m. – 1 p.m. & 6 p.m. – 11 p.m.	3.021¢
1 p.m. – 6 p.m.	7.598¢
Weekends	
11 p.m. – 6 a.m.	1.785¢
6 a.m. – 11 p.m.	3.021¢
Critical Peak Price	28.5¢

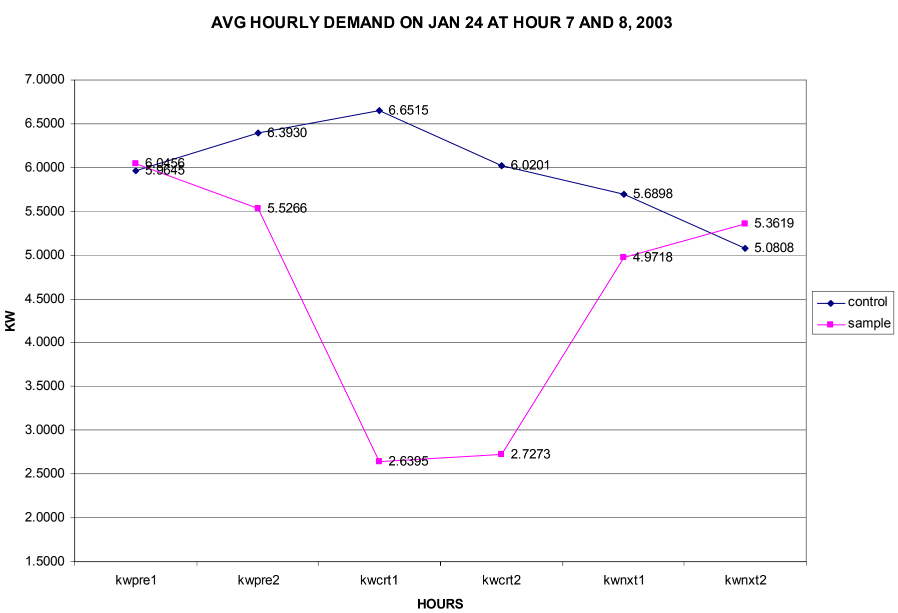
[14] Boisvert, Richard, Peter Cappers, Bernie Neenan, and Bryan Scott, “Industrial and Commercial Customer Response to Real Time Electricity Prices,” Neenan Associates Working Paper, December 10, 2004.

[15] Steven Braithwait and Mike O’Sheasy. "RTP Customer Demand Response: Empirical Evidence of How Much To Expect," found in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston: Kluwer Academic Publishers, 2002.

November – April	
Weekdays	
11 p.m. – 5 a.m.	1.785¢
5 a.m. – 6 a.m. & 10 a.m. – 11 p.m.	3.021¢
6 a.m. – 10 a.m.	7.598¢
Weekends	
11 p.m. – 6 a.m.	1.785¢
6 a.m. – 11 p.m.	3.021¢
Critical Peak Price	28.5¢

The critical peak price of 28.5¢ is determined at the sole discretion of the utility. Each customer is notified of the critical price by electronic signal at least one-half hour prior to it going into effect.

The load reduction results from this program have been widely cited as evidence of the demand-response potential for small-use customers. A presentation by Brian White, a product manager at Gulf Power provides this snapshot example of the potential for demand response from announced critical peak prices.[16] The graph below demonstrates the demand reduction exhibited by customers on the critical peak program (the lower line) compared to a control group on standard prices (the higher line) during times of the critical peak prices.



The GoodCents Select Program is approaching 9,000 participants.[17]

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[16] Presentation of Brian White to the Large Public Power Counsel Rates Committee, Phoenix, Arizona, October 29, 2004.

[17] Telephone conversation between Ross Hemphill and Brian White, July 14, 2006.

2. Pacific Gas & Electric Pricing Pilot

California is in the midst of a state-wide pricing pilot in which all regulated utilities (and a number of publicly-owned) are implementing various forms of dynamic pricing programs in order to evaluate the effect of price signals on demand response. One program representative of this effort is a CPP experiment being conducted by Pacific Gas and Electric Company (PG&E). Using statistical sampling, PG&E selected a group of customers to be placed on the dynamic prices and a control group of customers remaining on the standard flat prices. Customers chosen for the dynamic pricing can opt out of the program if they wish. An example of the CPP schedule is as follows.

Off-peak	8.039¢	Hours other than specified below
Peak	23.096¢	Hours between 2 p.m. and 7 p.m. weekdays
Super-peak	67.439¢	Defined below

Super Peak shall be all hours between 2 p.m. and 7 p.m. for no more than fifteen (15) days per calendar year and no more than three (3) consecutive days. Up to twelve (12) Critical-Peak pricing periods will be scheduled during the summer billing season, and up to three (3) during the winter billing season. Each customer shall be notified that the Super Peak is effective, by 5:00 p.m. the day prior to implementation of the Super Peak day.

The program was scheduled to be completed at the end of 2006 and evaluations of the demand response and determinations of the net benefits will be competed during the months following.

III. The Benefits of Time-based Rates

The benefits to TVA of expanding the application of time-based rates include the societal benefits resulting from more efficient pricing, i.e. the benefits to the region from prices reflecting more accurately the actual cost of power product. Some of the benefits come from the savings to TVA customers when they respond to time-based pricing structures. On the supply side, customer response can reduce the need for generation transmission capacity as well as fuel, and can help reduce environmental emissions. This section discusses the benefits of time-based pricing in more detail.

A. Theoretical Rationale for Time-Based Pricing

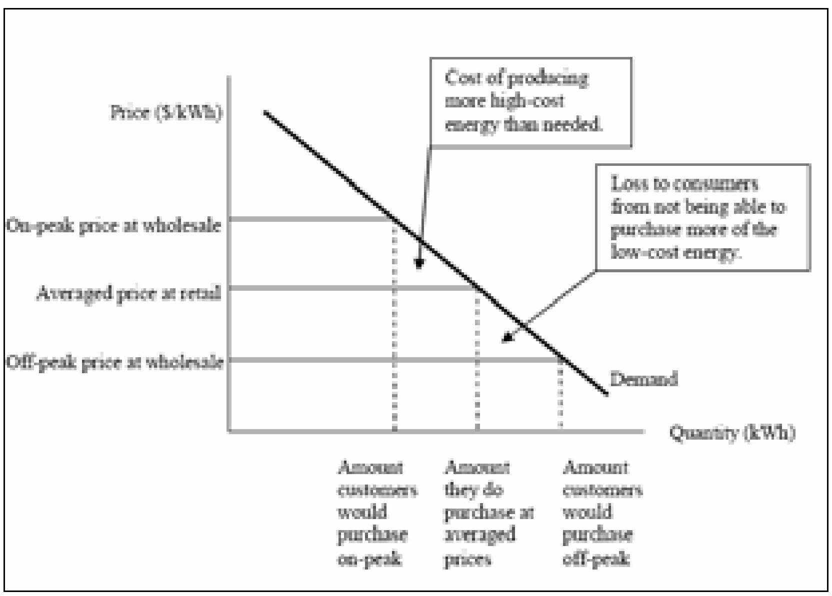
The principal argument made by economists in favor of time-based pricing is always based on economic efficiency. Wholesale power costs vary substantially across hours, days, and seasons. However, customers on a flat rate have no incentive to cut back usage during periods when wholesale power costs are at their highest, leading to higher costs to supply customers than would occur if their loads were less coincident with the system peak.

Policies that fail to accurately reflect cost differences across time periods blur the price signals customers use to make their consumption decisions. This blurring of the price signals results in an inefficient allocation of resources, referred to by economists as a "deadweight loss" to society. As illustrated in Figure 1, there are two types of deadweight losses resulting from flat pricing.

First there are the deadweight losses from charging too high a price in some hours; therefore energy consumed in those hours is inefficiently low. Second, there is the deadweight loss from charging too low a price in the peak hours resulting in inefficiently high consumption of energy and capacity – the marginal cost of replacing this consumption is above the revenues collected from the consumers.

A time-based pricing structure properly reflects differences in the cost of generating and delivering power across time periods, thus providing more appropriate price signals to customers than exhibited under flat rates. Customers can achieve benefits under time-based pricing if they are willing and able to shift sufficient consumption from peak-period hours, in which the cost-based price exceeds the standard flat rate, to lower-priced off-peak hours. The system realizes net gains from these same load shifts by avoiding the peak period sales whose costs exceed the revenue generated, and selling more during low-cost off-peak periods.

Figure 1 - Deadweight losses from prices that differ from underlying marginal costs[18]



Sally Hunt explains the core analysis that needs to be performed to determine how significant these gains might be, relative to the additional metering costs needed to implement the time-based rate:

[18] This is a modified version of a figure from: Sally Hunt, *Making Competition Work in Electricity* (New York: John Wiley & Sons, Inc., 2002), p. 81 as provided in Gordon, et al.

> [f]or any given situation, the value of metering depends on how distorted the averaged pricing is, on the absolute size of customers, and on how responsive their demand is.[19]

B. Demand-Response Potential

The direct benefits of a time-based pricing program are derived from the costs avoided due to the demand response of the participating customers. As described above, there is ample evidence that customers will respond when faced with significant price differentials. For example, in the late 1980's Central Maine Power Company introduced a mandatory TOU rate program for its residential customers exceeding 2,000 kWh in any winter month. This amounted to about 5% of the utility's residential customer usage. The program demonstrated significant impact on usage patterns, with customers reducing their overall consumption by 5% to 12% compared to previous years. The net effect has benefited the utility by reducing the residential customer's contribution during winter peak periods by 14%.[20]

The propensity for customer response to electricity prices is also supported by many studies time-of-use and real-time pricing programs that have been conducted over the years as evidenced by the sample of literature shown in Appendix C. One survey of such literature performed by the Electric Power Research Institute (EPRI) summarized the ranges of elasticities by customer group. The EPRI report found the midpoint of estimates for long-run elasticities for the industrial class to be -1.20, which means a 10% increase in price would lead to as much as a 12% reduction in demand during the relevant time period.[21]

TVA staff believes that the potential benefits of broader implementation of time-based rates are large. The peak demand served by the TVA system has increased 20% from 1997 to 2006 and this was a continuous year-to-year growth with the exception of 2006. So it behooves us to investigate ways to reduce this peak-load growth and improve the system load factor. Therefore more work should be done to assess the potential demand savings of time-based rates for the TVA system, relative to the costs of implementation. However, to develop a preliminary range of the potential benefits, we used the estimates of the average price responses experience by other utilities across the United States which is provided in the EPRI report cited above.

At the high end of the range of potential savings, if time differentiated rates were made mandatory for all residential, commercial and industrial customers in the Tennessee Valley and the price response was comparable to the average response other utilities experienced across the country, the long-term result would be a peak demand reduction

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19 Hunt, op. cit., p. 83.

20 *Impact Study of Residential Time-of-Use Rates*, Central Maine Power Company December, 1990.

21 Electric Power Research Institute, "Customer Response to Electricity Prices: Information to Support Wholesale Price Forecasting and Market Analysis, Report 1005945. November 2001."

of 2,274 MW for the system as a whole, and annual savings through capacity deferrals of $140 million per year.

At the low end of the range, if time differentiated rates were only made mandatory for commercial and industrial customers larger than 1 MW, and their price response was only equal to the low end of the range of elasticity estimates for commercial and industrial, the result would be a peak demand reduction of 210 MW and annual savings through capacity deferrals of $12.8 million.[22]

These savings are gross estimates due to capacity deferrals alone. Shifting load from peak to off-peak periods could also produce savings by reducing fuel and purchased power costs.) The estimates do not reflect the costs of implementing time-based rates (additional metering, telecommunications, meter reading and billing costs). Although implementation costs can be substantial, they would be lower for those distributors who have already deployed some level of advanced metering. (See Section IV.B.)

IV. Issues with the Implementation of Advanced Metering

A. Recent Cost Estimates for Advanced Metering

The cost of advanced interval meters has historically been a concern with the introduction of time-based pricing. Costs that should be considered in this evaluation include, but are not limited to:

- Investments in meters and other required infrastructure
- Changes to billing processes
- Technology and data collection upgrades
- Support for technology and data analyses
- Consumer education and customer service

There is evidence that the deployment of advanced metering has declined substantially in recent years and is becoming more economical. An EEI report on advanced metering technology prepared by Plexus Research, Inc. states

> At this time, costs for automated remote meter reading (that is, not including demand response functions such as customer signaling, load control or other demand response equipment) are approximately $100 to $175 per meter, including meters, all installation, and integration only with the monthly billing process.[23]

[22] The system savings may be determined by multiplying $5.12 X 12 for an annual demand side savings.

[23] Plexus Research, Inc., Deciding On 'Smart' Meters: The Technology Implications Of Section 1252 of the Energy Policy Act of 2005, Prepared for Edison Electric Institute, August 2006.

The following table provides some detail on these cost estimates. In addition, the Plexus report provides a very good tutorial on the range of technologies currently available at these costs.

AMI System Type	Cost ($ per meter)
Walk / drive-by (radio)	$50 - $90
Radio fixed network	$100 - $160
Power line fixed network	$110 - $175

Notes

Figures shown include hardware, software, installation, integration with billing only, training, & vendor deployment support.

Costs vary widely; figures shown are approximate, middle-of-range, for estimating purposes only.

Actual values will vary substantially with size of project, geography, customer density, functional requirements, meter inventory, corporate strategy, & many other factors.

Drive-by does not always cost less than fixed network. A power line system may cost less than a radio system.

O&M costs are not shown, vary widely, and appreciably affect annual net benefit.

Product status, risks, performance & other factors vary widely & often have cost & benefit consequences.

Assumptions

Saturation deployment.

Typical mix of single-, network-, & poly-phase meters.

50/50 meter retrofit/replacement.

B. Deployment of Advanced Metering by the Power Distributors

In cooperation with Tennessee Valley Public Power Association (TVPPA), TVA asked Schulman, Ronca, and Bucuvalas, Inc., (SRBI) for assistance in conducting a survey regarding automated meter reading (AMR) deployment by the Power distributors. One hundred forty-eight Power distributors completed the survey by email, fax, or telephone. Major survey findings include the following:[24]

Distributor Interest in AMR Deployment. AMR has received considerable attention from Power distributors: 43 percent of responding Power distributors have done “lots of research” about AMR deployment, while 32 percent have conducted “some research”. Most Power distributors take a considerable amount of time to consider AMR deployment, with 35 percent considering AMR deployment for more than one year.

[24] Findings are from the executive summary of “TVPPA Automated Meter Reading (AMR) Survey,” Prepared by Schulman, Ronca, & Bucuvalas, Inc., January 2006

The AMR Deployment Decision. Among those who have made a decision about AMR deployment, 79 percent have decided to implement AMR. Eighty-eight percent of these Power distributors have already begun deployment of a planned AMR system. Many distributors deciding not to implement AMR cite cost-related concerns.

Full vs. Partial Deployment. Seventy-three percent of Power distributors who are implementing AMR have decided on full deployment, while 26 percent are pursuing partial deployment. Power distributors planning partial AMR deployment are targeting hard-to-read meters (63 percent), accounts with frequent moves, connects and disconnects (42 percent), accounts with payment issues (37 percent), and accounts with frequent billing complaints and disputes (26 percent).

Meter Reading. While virtually all of the Power distributors deploying an AMR system will use it to read electric meters, 24 percent will also use their system to read water meters and 14 percent to read gas meters.

Status of AMR Deployment. Fourteen percent of respondents planning to install AMR have already completed the deployment of their AMR system, and 11 percent plan to do so within a year. However, 17 percent estimate that it will be four or more years before their AMR system is completed.

AMR Vendors and Installation. Power distributors are obtaining their AMR systems through a variety of vendors. Eighty-eight percent of those planning to deploy AMR are having existing in-house staff install the meters.

Meter Functions. Virtually all distributors plan to use their system for automated meter reading, while 78 percent will use it for theft and tampering detection, 65 percent for outage assessment, and 62 percent for remote connection and disconnection. Other distributor uses of their AMR systems include interval data (47 percent), data to the customer (47 percent), time-of-use rates (18 percent), load control (16 percent), and prepayment (12 percent).

Cost. The modal cost to install a meter is between $100 and $124. The average per-meter cost is $113.

C. Other Benefits of Advanced Metering

In his advisory paper to EEI, Kenneth Gordon recommends that any analysis of the incremental costs of advanced metering should include identification and quantification of the cost reductions resulting from the “key additional capabilities” resulting from this new technology.

> Most existing meters are not able to record usage by narrow periods of time within a day or week. They require a meter reader to collect gross usage data from a digital (or sometimes analogue) display. Smart metering allows a utility to collect customers’ hourly usage and peak-demand data for 15 minute (or potentially even shorter) intervals. It therefore allows for hourly-based and/or time-based pricing.

> This means that a number of more complicated time-based pricing approaches are feasible. Therefore, smart meters have the potential to offer a number of benefits to both the utility and the consumer, including better information and control of energy use, new service opportunities for companies, enhanced power network management facilities, and connection to digital services. AMR can significantly reduce business costs by replacing manual meter reading, eliminating the need to issue estimated bills and thereby significantly decreasing the cost of dealing with billing questions.[25]

The Plexus report to EEI regarding smart metering technology provides a detailed example of the process for calculating the net incremental costs of installing these new technologies.[26]

[25] Gordon, et al., op. cit., p. 10.

[26] Plexus Research, Inc., op. cit., p. 23.

Appendix A: Status of Neighboring States' PURPA Consideration Process

State	Process Initiated	Process Deadlines	Decision
Alabama	1) Smart Metering 2) Interconnection	To be recommended by staff if needed.	On September 15, 2006, the Alabama Public Service Commission established a docket on the Smart Metering and Interconnection standards and directed its staff to review whether any prior action by the Commission or the state legislature negates the requirement that the standard be considered. No further action has been taken in this docket.
Arkansas	1) Smart Metering 2) Interconnection 3) Net Metering 4) Fuel Diversity 5) Fossil Fuel Generation Efficiency	Smart Metering • Initial comments Oct. 27, 2006 • Reply comments Nov. 10, 2006 • Public Hearing Dec. 13, 2006 Fuel Diversity • Initial comments April 7, 2006 • Reply comments May 5, 2006 • Public Hearing May 23, 2006 Net Metering, Fossil Fuel Generation Efficiency, Interconnection • Initial comments Oct. 20, 2006 • Reply comments December 20, 2006	None

State	Process Initiated	Process Deadlines	Decision
Georgia	1) Smart Metering 2) Interconnection 3) Net Metering 4) Fossil Fuel Generation Efficiency 5) Fuel Diversity	Will be considered as part of 2007 Integrated Resource Planning (IRP) required by Georgia law. • Georgia Power to file IRP January 31, 2007 • Decision prior to August 8, 2007	None
Kentucky	1) Smart Metering 2) Interconnection	• Initial Responses March 23, 2006 • Supplemental Responses April 13, 2006 • Public Hearing July 18, 2006 • Briefs Aug. 30, 2006	None
Mississippi	1) Smart Metering 2) Interconnection	• Public Hearing Dec. 5, 2006	None

State	Process Initiated	Process Deadlines	Decision
North Carolina	1) Smart Metering 2) Interconnection 3) Net Metering 4) Fuel Diversity 5) Fossil Fuel Generation Efficiency	Net Metering & Interconnection (for comments on preliminary conclusion that previously adopted standards meet requirements of EPAct 2005) • Initial comments Oct. 13, 2006 • Reply comments Nov. 17, 2006 Smart Metering, Fossil Fuel Generation Efficiency, and Fuel Diversity • Hearing Dec. 11-12 , 2006	On August 4, 2006, the North Carolina Utilities Commission reached a preliminary conclusion that previous consideration and adoption of Net Metering and Interconnection standards meets the requirements of EPAct 2005. However, it opened a docket to receive comments on that preliminary conclusion. That docket is still pending and there have been no decisions on the remaining standards. Under the previously approved Net Metering standard, net metering is available to a utility customer that owns and operates a solar PV, wind-powered, or biomass-fueled renewable energy facility without battery storage. The renewable energy facility may have a capacity up to 20 kW for a residential customer-generator and 100 kW for a non-residential customer-generator. The standard also provides for continued review of the implementation and use of net metering. The requirements of the previously approved Interconnection standard include (a) a manual load-break disconnect switch to isolate the generator, (b) the customer generator to bear all the cost of interconnection, (c) a residential customer generator to have a standard homeowner's insurance policy with at least $100,000 coverage, and (d) a non-residential customer generator to have at least $300,000 insurance coverage.

State	Process Initiated	Process Deadlines	Decision
Virginia	1) Smart Metering 2) Interconnection 3) Net Metering 4) Fuel Diversity 5) Fossil Fuel Generation Efficiency	Smart Metering • Comments May 12, 2006 • Staff comments June 9, 2006 Net Metering, Fuel Diversity, and Fossil Fuel Generation Efficiency • Comments March 31, 2006 • Staff comments April 28, 2006 Interconnection • Comments June 9, 2006 • Staff comments July 12, 2006	On August 8, 2006, the State Corporation Commission *declined adoption* of the Interconnection standard as proposed on the ground that it was not appropriate for implementation in Virginia. The Commission opened a separate docket to establish interconnection standards in accordance with the distributed generation statue contained the Virginia Electric Utility Restructuring Act. There have been no decisions on the remaining standards.

Appendix B: Survey of Time Based Pricing

Table B.1. US Utilities Included in Survey

Utility Name	Service Area	Ownership	Customers (2003)	Sales (MWh) (2003)	Web Site
AEP (Indiana Michigan)	Michigan	IOU	448,948	15,265,235	http://www.aep.com/
Alabama Power Co	Alabama	IOU	1,363,120	52,208,020	http://www.southernco.com
Allegheny Power (West Penn)	Pennsylvania	IOU	693,432	18,991,265	http://www.alleghenypower.com/
Ameren Union Electric	Missouri	IOU	1,170,848	31,901,036	http://www.ameren.com/
Arizona Public Service	Arizona	IOU	931,462	24,562,305	http://www.aps.com/home
Baltimore Gas and Electric	Maryland	IOU	1,174,814	31,114,062	http://www.bge.com/
Bangor Hydro	Maine	IOU	110,000		http://www.bhe.com/
Boston Edison (NSTAR)	Massachusetts	IOU	687,315	11,678,710	http://www.nstaronline.com/
Carolina Power & Light Co (Progress Energy)	North Carolina	IOU	1,156,579	34,857,713	http://www.progress-energy.com/
Cinergy (CG&E)	Ohio	IOU	641,688	16,796,420	http://www.cinergy.com/
Commonwealth Edison	Illinois	IOU	3,629,605	68,384,237	http://www.exeloncorp.com
Connecticut Light & Power Co	Connecticut	IOU	1,146,977	30,628,082	http://www.cl-p.com/
Consolidated Edison	New York	IOU	3,137,300	23,517,194	http://www.coned.com
Consumers Energy Company	Michigan	IOU	1,741,397	34,238,970	http://www.consumersenergy.com
Detroit Edison	Michigan	IOU	2,134,371	43,671,787	http://dteenergy.com
Dominion Virginia	Virginia	IOU	2,094,286	68,323,177	http://www.dom.com
Duke Energy Corporation	North Carolina	IOU	1,664,280	53,024,862	http://www.dukepower.com
Duquesne Light	Pennsylvania	IOU	439,155	9,654,461	http://www.duquesnelight.com
El Paso Electric	Texas	IOU	244,876	5,042,868	http://www.epelectric.com
Florida Power and Light	Florida	IOU	4,117,229	99,339,144	http://www.fpl.com
Florida Power Corp (Progress Energy)	Florida	IOU	1,510,494	37,956,702	http://www.progress-energy.com/
Georgia Power	Georgia	IOU	2,019,934	75,018,318	http://www.southernco.com
Gulf Power	Florida	IOU	389,807	10,884,789	http://www.southernco.com
Idaho Power	Idaho	IOU	408,829	12,351,079	http://www.idahopower.com/
Indianapolis Power and Light Co (IPALCO)	Indiana	IOU	452,340	14,355,738	http://www.ipalco.com/
Jacksonville Electric	Florida	Muni	378,500	12,293,323	http://www.jea.com/
Jersey Central Power & Lt Co	New Jersey	IOU	987,636	18,786,247	http://www.firstenergycorp.com
Kansas City Power and Light (KCPL)	Missouri	IOU	265,829	8,256,870	http://www.kcpl.com
LADWP	California	Muni	1,535,271	23,040,163	http://www.ladwp.com
Long Island Power Authority	New York	Muni	1,082,903	18,834,909	http://www.lipower.org/

Utility Name	Service Area	Ownership	Customers (2003)	Sales (MWh) (2003)	Web Site
Massachusetts Electric Co (National Grid)	Massachusetts	IOU	1,189,951	17,212,298	http://www.nationalgridus.com/masselectric/
Niagara Mohawk (National Grid)	New York	IOU	1,500,299	20,934,910	http://www.nationalgridus.com/niagaramohawk/
Northern States Power (Xcel)	Minnesota	IOU	1,163,850	30,417,980	http://www.xcelenergy.com
Ohio Edison (First Energy)	Ohio	IOU	713,508	16,879,469	http://www.firstenergycorp.com
Pacific Power (PacifiCorp)	Oregon	IOU	514,403	13,227,334	http://www.pacificpower.net
PECO Energy (Exelon)	Pennsylvania	IOU	1,217,724	33,707,980	http://www.exeloncorp.com
PG&E	California	IOU	4,870,671	47,881,180	http://www.pge.com
Potomac Electric Power (PEPCO)	Washington, D.C.	IOU	420,776	10,468,174	http://www.pepco.com
PPL Electric Utilities	Pennsylvania	IOU	1,313,084	33,635,019	http://www.pplelectric.com/
Public Service Co of Colorado	Colorado	IOU	1,277,525	25,845,962	http://www.xcelenergy.com
Public Service Elec & Gas Co	New Jersey	IOU	2,033,550	38,766,006	http://www.pseg.com
Puget Sound Energy (PSE)	Washington	IOU	968,586	19,591,637	http://www.pse.com
SCE	California	IOU	4,528,289	52,229,092	http://www.sce.com
SDG&E	California	IOU	1,279,238	10,048,511	http://www.sdge.com
SMUD	California	Muni	547,651	9,917,373	http://www.smud.org
TXU Electric Delivery	Texas	IOU	2,608,390	79,049,806	http://www.txuelectricdelivery.com
United Illuminating (UI)	Connecticut	IOU	320,993	5,763,052	http://www.uinet.com/
Wisconsin Electric Power Co (WE Energies)	Wisconsin	IOU	1,033,818	24,858,918	http://www.we-energies.com
Wisconsin Public Service (WPS)	Wisconsin	IOU	401,701	10,388,244	http://www.wisconsinpublicservice.com

Table B.2. International Utilities Included in Survey: Basic Information

Utility Name	Service Area	Ownership	Web Site
ACEA-Electrabel	Italy	Private	http://www.aceaelectrabelelettricita.it
Bewag (Vattenfall)	Germany	Private	http://www.bewag.de
China Light and Power	Hong Kong	Private	http://www.clpgroup.com
Electrabel	Belgium	Private	http://www.electrabel.com
Electricidade de Portugal (EDP)	Portugal	Private	http://www.edp.pt
Electricite de France (EDF)	France	State	http://www.edf.fr
Enel SPA	Italy	Private	http://www.enel.it
EnviaM (RWE)	Germany	Private	http://www.enviam.de
Hydro One	Canada	State	http://www.hydroonenetworks.com
London Energy (EDF Energy)	UK	Private	http://www.london-energy.com
NUON	Holland	Private	http://www.nuon.nl
RAO-UES (United Energy System of Russia)	Russia	State	http://www.rao-ees.ru
Tokyo Electric Power Co (TEPCO)	Japan	Private	http://www.tepco.co.jp
Vattenfall	Sweden	Private	http://www.vattenfall.se

Table B.3. Residential DR Rate Options Used by US and International Utilities (includes current and historic programs)

Utility	Tariff or program names	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
AEP (Indiana Michigan)	TD, LM-TD	X				X		
Alabama Power Co	FDT	X						
Allegheny Power (West Penn)	EPRP		X			X		X
Ameren Union Electric	Time of Day	X						
Arizona Public Service	ET-1	X						
Baltimore Gas and Electricity	RL-2, Saver Switch	X				X		
Bangor Hydro	Time of Use	X						
Boston Edison (NSTAR)	R-5	X						
Carolina Power & Light Co (Progress Energy)	R-TOUE, R-TOUD	X						
Cinergy	TD	X						
Commonwealth Edison	1DR, RHEP, Nature First	X	X			X		
Connecticut Light & Power Co	Rate 7	X						
Consolidated Edison	Rate II	X						
Consumers Energy Company	A-3	X						
Detroit Edison	D1.1, D1.2	X				X		
Dominion Virginia	R1S, R1T, Schedule J	X				X		
Duke Energy Corporation	RT, RTE	X						
Duquesne Light	None							
El Paso Electric	Time of Use	X						
Florida Power and Light	On Call					X		
Florida Power Corp (Progress Energy)	EMP					X		
Georgia Power	TOU-REO-2	X						
Gulf Power	RSVP	X		X				
Idaho Power	Time of Day, Energy Watch	X		X		X		
Indianapolis Power and Light Co (IPALCO)	None					X		
Jacksonville Electric	Time of Day	X						
Jersey Central Power & Lt Co	RT	X						
Kansas City Power and Light (KCPL)	RTOD	X						
LADWP	Time of Use	X						
Long Island Power Authority	Rate 184	X						
Massachusetts Electric Co (National Grid)	R-4	X						
Niagara Mohawk (National Grid)	SC-1C	X						

Utility	Tariff or program names	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
Northern States Power (Xcel)	Saver's Switch					X		
Ohio Edison (First Energy)	Time of Day	X				X		
Pacific Power (PacifiCorp)	RS4	X						
PECO Energy (Exelon)	RT	X						
PG&E	E3, E7	X		X				
Potomac Electric Power (PEPCO)	Kilowatchers, RTM	X				X		
PPL Electric Utilities	Time of Day	X						
Public Service of Colorado (Excel)	RT	X						
PSE&G New Jersey	RLM	X						
Puget Sound Energy (PSE)	Time of Day	X						
SCE	Summer Discount, DSS				X	X		
SDG&E	DR-TOU	X						
SMUD	Time of Use, Peak Corps	X						
TXU Electric Delivery	None							
United Illuminating (UI)	RT	X						
Wisconsin Electric Power Co (WE Energies)	RG2	X						
Wisconsin Public Service (WPS)	TOU, HELP	X				X		
ACEA-Electrabel	Uso Abitazione				X			
Bewag (Vattenfall)	Zeitzonen	X						
China Light and Power	None							
Electrabel		X						
Electricidade de Portugal (EDP)	Bi-Horaria	X			X			
Electricite de France (EDF)	Base, Heures Creues, Tempo	X		X	X			
Enel SPA	Due (two)	X			X			
EnviaM (RWE)	EnviaM base night	X						
Hydro One	None							
London Energy (EDF Energy)	Economy 7	X						
NUON (Holland)	Strom Zakelijk	X						
Powergen (UK)	Economy 7	X						
RAO-UES (United Energy System of Russia)	None							
Tokyo Electric Power Co (TEPCO)	Meter Rate				X			
Vattenfall	Tidstariff	X						

Table B.4. Large-Customer DR Rate Options Used by US Utilities (includes current and historic programs)

Utility	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
AEP	X	X				X	
Alabama Power Co	X	X				X	
Allegheny Power (West Penn)	X					X	
Ameren Union Electric	X	X				X	
Arizona Public Service	X					X	
Baltimore Gas and Electricity	X					X	X
Bangor Hydro	X						
Boston Edison (NSTAR)	X					X	X
Carolina Power & Light Co (Progress Energy)	X	X				X	
Cinergy	X	X				X	X
Commonwealth Edison	X	X				X	
Connecticut Light & Power Co	X				X	X	X
Consolidated Edison	X	X				X	X
Consumers Energy Company	X					X	
Detroit Edison	X				X	X	
Dominion Virginia	X	X				X	
Duke Energy Corporation	X	X				X	
Duquesne Light	X	X					
El Paso Electric	X					X	
Florida Power and Light	X	X			X	X	
Florida Power Corp (Progress Energy)	X				X	X	
Georgia Power	X	X				X	
Gulf Power	X	X				X	
Idaho Power	X						
Indianapolis Power and Light	X					X	
Jacksonville Electric	X	X				X	
Jersey Central P&L	X	X					
Kansas City P&L	X	X				X	X
LADWP	X		X			X	
Long Island Power Authority	X	X					
Massachusetts Electric Co (National Grid)	X					X	X
Niagara Mohawk (National Grid)	X	X				X	X
Northern States Power (Xcel)	X	X				X	
Ohio Edison (First Energy)	X	X				X	
Pacific Power (PacifiCorp)	X					X	X
PECO Energy (Exelon)	X					X	
PG&E	X	X	X			X	X
Potomac Electric Power	X						
PPL Electric Utilities	X	X				X	X
Public Service of Colorado (Xcel)	X	X				X	

Utility	TOU	RTP	CPP	DSS	DLC	CIS	Hybrid
PSE&G New Jersey	X						
Puget Sound Energy						X	
SCE	X	X	X			X	X
SDG&E	X	X	X			X	X
SMUD	X						
TXU	X	X				X	
United Illuminating	X					X	
Wisconsin Electric Power Co (WE Energies)	X	X			X	X	X
Wisconsin Public Service	X				X	X	X

Table B.5. TOU Tariffs Offered by US and International Utilities

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
AEP (Indiana Michigan Power)	RS-LM-TOD	2-period, 1-season TOU plus load management technology	7.92	1.87	4.2	S	V	In	1.85	http://www.aepcustomer.com/tariffs/Michigan/pdf/MISTDA4-28-05.pdf	0.0105/kWh credit for installing off-peak only water and space heating
Alabama Power Co	FDT	3 period summer, 2 period winter TOU	16.72	1.83	9.1	S	V	In	13.00	http://www.southerncompany.com/alpower/pricing/bestpricing.asp?mnuOpco=apc&mnuType=res&mnuItem=ps	
Ameren Union Electric	Optional Time of Day Rate	2 period, 2 season TOU	11.11	3.24	3.4	S	V	In	7.75	https://www2.ameren.com/ACMSContent/Rates/Rates_umbe28rt1M.pdf	
Arizona Public Service Co	ET-1	2 period, 2 season TOU	13.30	4.30	3.1	S	V	In	14.00	http://www.aps.com/images/pdf/et-1.pdf	
Arizona Public Service Co	ECT-1R	2 period, 2 season TOU for energy and demand	4.80	2.60	1.8	S	V	In	14.00	http://www.aps.com/images/pdf/ect-1r.pdf	
Baltimore Gas and Electricity (BGE)	RL-2	3-period, 2-season TOU	8.04	2.99	2.7	S	V	In	4.50	http://www.bge.com/CDA/Files/arschrl2.doc	must have central AC
Bangor Hydro	Time-of-Use	2 period, 2 season TOU	9.36	4.14	2.3	S	V/M*	In	3.95	http://www.bhe.com/data/pdf/rate_schedules/pg6res_restou_0305.pdf	*mandatory for > 2000 kWh/month
Bewag	Zeitzonen	2 period, year-round TOU	23.35	13.41	1.7	S	V	In	3.13	http://www.bewag.de/Produkte_1/Produkte_1.jsp?id=681f52_f2daaabeb0_7059192616861660	
Boston Edison (NSTAR)	R-5	2 period, 2 season TOU	19.09	9.12	2.1	S	V	In	3.56	http://www.nstaronline.com/ss/customer_service/rates/rates.asp#A5	
Carolina Power & Light Co	R-TOUD	2 period, 2 season TOU for energy and demand	4.88	3.51	1.4	S	V	In	10.00	http://www.progressenergy.com/aboutenergy/rates/01_01_05/NCScheduleR-TOUD-3.pdf	

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
Carolina Power & Light Co	R-TOUE	2 period, 2 season TOU	15.16	3.51	4.3	S	V	In	10.00	http://www.progressenergy.com/aboutenergy/rates/01_01_05/NCScheduleR-TOUE-3.pdf	
Cinergy	Rate TD	2 period, 2 season TOU	14.95	2.25	6.6	S	V	In	6.00	http://www.cinergycge.com/pdfs/td.pdf	
Commonwealth Edison (Exelon)	Rate 1DR	2 period, 2 season TOU, with two-tier inverted block price off-peak	20.91	3.52	5.9	S	V	In	6.12	http://www.exeloncorp.com/comed/library/pdfs/0_ratebook.pdf	
ConEd	Rate II	2 period, 2 season TOU	18.26	0.63	29.0	S	V	In	4.79	http://m020w1.coned.com/documents/elec/201-210.pdf	
Connecticut Light & Power Co	Rate 7	2 period, year round TOU	11.47	7.97	1.4	S	V	In		http://www.clp.com/clpcommon/PDFs/online/business/bill/rates/rate7.PDF	must be >1000 kWh/month
Consumers Energy Company	A-3	2 period, year round TOU	14.60	3.60	4.1	S	V	In	6.18	http://www.consumersenergy.com/tariffs.nsf/ELECTRIC_TARIFFS/67B0DEF59F26908D85256F65005728BF/$FILE/elerates.pdf?Open	limited to 5000 customers, >750 kWh/month
Detroit Edison	D1.2	2 period, 2 season TOU	20.53	2.93	7.0	S	V	In	19.00	http://my.dteenergy.com/myAccount/pdfs/rates.pdf	
Dominion Virginia	R1S	2 period, 2 season TOU for energy and demand	3.72	1.80	2.1	S	V	In	5.00	http://www.dom.com/customer/pdf/va/vab1s.pdf	demand$6.32/kw peak, $4.64/kW off peak
Dominion Virginia	R1T	2 period, 2 season TOU	15.00	1.40	10.7	S	V	In	5.00	http://www.dom.com/customer/pdf/va/vab1t.pdf	
Duke Energy Corporation	RT	2 period, 2 season TOU for energy and demand	4.84	3.85	1.3	S	V	In	4.66	http://www.dukepower.com/aboutus/rates/ncrates/NCScheduleRT.PDF	$6.46/kw peak, $3.22/kW off peak
Duke Energy Corporation	RTE	2 period, 2 season TOU	20.84	3.85	5.4	S	V	In	5.22	http://www.dukepower.com/aboutus/rates/ncrates/NCScheduleRTE.PDF	

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
El Paso Electric	Alternate Time-of-Use	2 period, year-round TOU	12.52	4.75	2.6	P	V	In	1.50	http://www.epelectric.com/internetsite/yhome.nsf/f5a02237b9a921fd87256bc6005e40cf/d0a5b5aef306646a87256bc600641 4d6/$FILE/Sch01.pdf	limited to 250 customers
Electricidade de Portugal	tarifa bi-horaria	Demand subscription (3.45 to 20.7 kW in 10 increments) + 2 period, year-round TOU energy rate	17.13	6.75	2.5	S	V	In	2.74	http://www.edp.pt/index.asp?CID=402300&LID=pt&MID=1&OID=3010000&PID=3000000&SESSID=o50B00I20s00x07F1W5q4Ds	used 3.45 kVA to calculate customer charge
Electricidade de Portugal	Tarifa tri-horaria	Demand subscription (3.45 to 20.7 kW) + 3 period, year-round TOU energy rate	27.33	6.75	4.0	S	V	In	4.91	http://www.edp.pt/index.asp?CID=402300&LID=pt&MID=1&OID=3010000&PID=3000000&SESSID=o50B00I20s00x07F1W5q4Ds	used 3.45 kVA to calculate customer charge
ENEL SPA	Tariffa bioraria “Due”	Demand subscription (3-15 kVA) + 2 period, year-round TOU, with 3 options	15.28	12.78	1.2	S	V	In	2.89	http://www.enel.it/sportello_online/elettricita/tariffe_elettriche/tariffe_due_costi.asp	used 3.0 kVA to calculate customer charge
EnviaM	EnviaM base night	2 period, year-round TOU	23.80	13.81	1.7	S	V	In	0.00	http://www.enviam.de/produkte/strom/privat/produkte_strom_privatkunden_enviam_basis.html	
Georgia Power	TOU-REO2	2 period, 2 season TOU with block pricing in winter	16.07	2.77	5.8	S	V	In	2.25	http://www.southerncompany.com/gapower/pricin g/gpc-pdf/TOU-REO2.pdf	
Idaho Power	Time-of-Day	3 period summer, 1 period winter TOU	7.08	5.58	1.3	P	V	In	0.00	http://www.idahopower.com/aboutus/regulatoryinfo/tariffPdf.asp?id=264&.pdf	
Jacksonville Electric	Time-of-Day	4 period summer, 2 period winter TOU	8.46	2.59	3.3	S	V	In	4.50	http://www.jea.com/about/pub/downloads/ElectricTariff-LEGAL.pdf	

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
Jersey Central Power & Light (First Energy)	RT	2 period, 2 season TOU	16.80	7.20	2.3	S	V	In	3.00	http://www.firstenergycorp.com:80/customercare/cache/_85256A170068279F_la_NJ+Part+III+20050601__file_tariff_iii_eff06 0105.pdf	
Kansas City Power and Light (KCPL)	RTOD	3 period, 2 season TOU	11.34	4.88	2.3	S	V	In	3.31	http://www.kcpl.com/motariff.pdf	
London Energy	Economy 7	2-period, year-round TOU; low period is composed of 2 declining blocks	13.17	3.17	4.2	S	V	In	0.00	http://www.londonenergy.com/showPage.do?name=homeenergy.switchBrand.prices.e7elec.til	
Long Island Power Authority	Rate 184	2 period, 2 season TOU, with two-tier inverted block price by usage level	27.60	7.70	3.6	S	V	In	22.00	http://www.lipower.org/pdfs/residential/resirates.pdf	must be >39,000 kWh/year
Los Angeles (LADWP)	Time-of-Use	3 period, year-round TOU	14.30	3.80	3.8	S	V	In		http://www.ladwp.com/ladwp/cms/ladwp004844.jsp	
Massachusetts Electric Co (National Grid)	R-4	2-period, year-round TOU	9.20	1.30	7.1	S	V	In	13.40	http://www.nationalgridus.com/masselectric/home/rates/4_tou.asp	must be >2500 kWh/month
Niagara Mohawk	SC-1C	3 period summer and winter, 1 period spring and fall TOU	17.06	3.66	4.7	S	V	In	21.61	http://www.nationalgridus.com/niagaramohawk/ho me/rates/4_tou.asp http://www.nationalgridus.com/niagaramohawk/non_html/rates_tou.pdf	
NUON	Strom zakelijk	2-period, year-round TOU	8.09	3.43	2.4	S	V	In	0.00	http://zakelijk.nuon.nl/zakelijk/Images/61_15063.pdf	
Ohio Edison (First Energy)	Optional Time of Day Rate	flat energy charge + demand charge; TOU periods are described but no time-dependent rates are given	2.91	2.91	1.0	S	V	In	2.70	http://www.firstenergycorp.com/customercare/cache/_85256A170068279F_la_OE+Current__file_OE_2005_PUCO_No11b.pdf	
Pacific Power (PacifiCorp)	RS4	4 period, 2 season TOU	6.12	2.19	2.8	S	V	In	1.50	http://www.pacificpower.net/Article/Article15450.html	

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
PECO Energy	RT	2 period, 2 season TOU	22.71	6.83	3.3	S	V	In	5.17	http://www.exeloncorp.com/peco/library/pdfs/s63_complete_2005a.pdf	
Pennsylvania Power and Light (PP&L)	Time-of-Day	2 period, year-round TOU	15.84	4.80	3.3	S	V	In	7.52	http://www.pplelectric.com/NR/rdonlyres/875DF9 43-EC8E-4852-BF6ABB28EF2168D4/0/ratertd.pdf	
PG&E	E-7	2 period, 2 season TOU, with customer baseline	29.37	8.66	3.4	S	V	In	3.51	http://www.pge.com/tariff s/pdf/E-7.pdf	
PG&E	E-2	2 period, 2 season TOU	23.97	9.84	2.4	P	V	In	0.00	http://www.pge.com/tariff s/pdf/E-2.pdf	used in statewide pilot project
Potomac Electric Power (PEPCO)	R-TM	3 period, 2 season TOU	11.42	10.41	1.1	S	V/M*	In	8.02	http://www.pepco.com/pdf/dc_rate-schedules.pdf	*mandatory for > 2500 kWh/month
Public Service Co of Colorado (Xcel)	RT	2 period, year round demand only TOU, energy is flat rate	1.65	1.65	1.0	S	V	In	17.30	http://www.xcelenergy.com/docs/corpcomm/psco_elec_entire_tariff.pdf	demand $6.58/kW on peak, $4.57 off peak
Public Service Elec & Gas Co	Residential Load Mgt	2 period, 2 season TOU	17.19	7.74	2.2	S	V	In	11.44	http://www.pseg.com/customer/home/bill/understanding.jsp#anchor0	
Puget Sound Energy (PSE)	Time-of-Day + PEM (personal energy mgt)	4-period, 2-season TOU	6.80	3.80	1.8	P	V	Out	1.00	http://www.pse.com/account/rates/rateselec.html	
SDG&E	DR-TOU	2 period, 2 season TOU, experimental	13.38	10.88	1.2	P	V	In	3.81	http://www.sdge.com/tm2/pdf/DR-TOU.pdf	
SMUD	Optional Time of Use Rate	2 period, 2 season TOU	20.39	8.09	2.5	S	V	In	0.00	http://www.smud.org/commercial/rate_schedules/1-R-1thru5.pdf	
United Illuminating (UI)	RT	2 period, 2 season TOU	17.90	8.70	2.1	S	V	In	0.00	http://www.uinet.com/pdfs/UnderstandingRT.pdf	
Vattenfall	Tidstariff	2 period winter, 1 period summer TOU	11.54	10.13	1.1	S	V	In	0.00	http://www.vattenfall.se/privat/priser_och_avtal/el/tillsvidarepris/	
Wisconsin Electric Power Co (WE Energies)	RG2	2 period, year-round TOU	15.04	2.74	5.5	S	V/M*	In	2.95	http://www.weenergies.com/pdfs/etariff s/wisconsin/ewi_sheet23 - 24.pdf	*mandatory for >60,000 kWh/yr

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	Peak/ Off Peak Ratio	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
Wisconsin Public Service (WPS)	Time-of-Use	2 period, 2 season TOU; customers can choose from 3 time options to define their TOU periods	17.70	4.17	4.2	S	V	In	2.00	http://www.wisconsinpublicservice.com/home/help.asp	

Table B.6. CPP Tariffs Offered by US and International Utilities

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	CPP Price ¢/kWh	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
Electricite de France	L'option tempo	Demand subscription + CPP with 2 period TOU for each of 3 categories of usage days, with day-ahead notification by utility. CPP days fall Nov 1 Mar 31. Has load management enabling technology.	6.91	5.58	58.78	S	V	In	4.77	http://particuliers.edf.fr/rubrique112.html	Must be 9 kVA or greater. Exchange rate: 1 Euro = 1.25 USD. Smart thermostat installed.
Gulf Power	RSVP / Good Cents Select	CPP with 3 period, 2 season TOU. CPP days year round, with 30 min notification by utility, with limit of 1% CPP hours in year. Has load management enabling technology.	11.0	5.2	31.9	S	V	In	4.95	http://www.southerncompany.com/gulfpower/pricing/pdf/rsvp.pdf	Smart thermostat installed.
Idaho Power	Energy Watch	CPP with flat-rate tariff. Day-ahead notification of CPP events by utility. CPP days fall June 15-Aug 15. Has load management enabling technology.	5.09	5.09	20.60	P	V	In	0.00	http://www.idahopower.com/aboutus/regulatoryinfo/tariffPdf.asp?id=263&.pdf	

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	CPP Price ¢/kWh	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
PG&E	E-3, Rate A	CPP with 2-period, 2 season TOU. CPP days year round, day-ahead notification, up to 15 days/yr, 12 in summer, up to 3 consecutive days. Usage above CBL in each TOU period charged at inclining block rate.	23.10	8.04	67.44	P	V	In	0.00	http://www.pge.com/tariff s/pdf/E-3.pdf	
PG&E	E-3, Rate B	CPP with 2-period, 2 season TOU. CPP days year round, day-ahead notification, up to 15 days/yr, 12 in summer, up to 3 consecutive days. No CBL, all usage charged at CPP/TOU rate.	16.32	8.36	39.36	P	V	In	0.00	http://www.pge.com/tariff s/pdf/E-3.pdf	
SCE	TOU-DCPPF-1	CPP with 2-period, 2 season TOU. CPP days year round, day-ahead notification, up to 15 days/yr, 12 in summer, up to 3 consecutive days. Usage above 130% of CBL charged at inclining block rate.	27.43	8.62	84.34	P	V	In	0.00	http://www.pge.com/tariff s/pdf/E-3.pdf	Tariff calculations based on 70% utility retained generation, 30% DWR.

Utility	Tariff Name	Description	On Peak Price ¢/kWh	Off Peak Price ¢/kWh	CPP Price ¢/kWh	Std vs Pilot?	Vol vs Man	Opt-in vs Opt-out	Cost $/mon	Tariff Web Site	Notes
SCE	TOU-DCPPF-2	CPP with 2-period, 2 season TOU. CPP days year round, day-ahead notification, up to 15 days/yr, 12 in summer, up to 3 consecutive days.	24.07	12.13	60.34	P	V	In	0.00	http://www.pge.com/tariff s/pdf/E-3.pdf	Tariff calculations based on 70% utility retained generation, 30% DWR.
SDG&E	EECCCPP-V	CPP with 2-period, 2 season TOU. Variable starting hour and duration, notification 4 hours ahead. Limited to 90 hrs/yr total. Has load management enabling technology	13.97	2.97	45.97	P	V	In	3.81	http://www.sdge.com/tm2/pdf/EECC-CPPV.pdf#page=1	Smart thermostat installed.
SDG&E	EECC-CPP-F	CPP with 2-period, 2-season TOU. CPP days year round, day-ahead notification, up to 15 days/yr, 12 in summer, up to 3 consecutive days. Usage above CBL in each TOU period charged at inclining block rate.	13.97	2.97	45.97	P	V	In	3.81	http://www.sdge.com/tm2/pdf/EECC-CPP-F.pdf#page=1	

Table B.7. Large Customer RTP Programs (current and historic, 24 US utilities from sample of 50)

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
AEP	Market Choice	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, symmetrically (3) has adders; also has interruptible option	> 1 MW	S	In	no	lambda	yes	2 PM previous day	http://www.aepcustomer.com/tariffs/Michigan/pdf/MISTD4-2805.pdf	no customers as of 2003
Alabama Power (Southern Co)	RTP	1-part energy RTP. (1) all energy charged at RTP, based on utility system lambda (2) has adder	> 3 MW	S	In	n/a	lambda	no	4 PM of previous day	http://www.southerncompany.com/alpower/pricing/bestpricing.asp?mnuOpco=apc&mnuType=res&mnuItem=ps	30 customers, 500 MW peak demand
Ameren UE	Rider RTP	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (adder on incremental usage) (3) unbundled GTD adders (4) ancillary service charges	all non-residential	S	In	no	lambda or trading desk	no	8 AM day ahead	https://www2.ameren.com/ACMSContent/Rates/Rates_umbe28rt1M.pdf	no customers had ever enrolled as of 2003

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Carolina Light & Power (Progress Energy)	LGS-RTP	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (adder on incremental usage) (3) has adders	> 1 MW	P	In	yes	lambda	no	4 PM of previous day	http://www.progressenergy.com/aboutenergy/rates/NC_Large_General_Service_RealTimePricing.pdf	85 customers (100% of target enrollment cap)
Cinergy	Path Wise	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (adder on incremental usage) (3) has adders (4) has unbundled T&D and ancillary service charges	> 100 kW	P	In	yes	lambda	yes	day-ahead	http://www.cinergycge.com/Business_Services/programs_and_services/default_1960.asp	250 customers originally, 140 in 2003
Commonwealth Edison (Exelon)	HEP	1-part energy RTP. (1) all energy charged at RTP, calculated based on index forecast with PJM hourly load shape (2) has adder (3) all non-commodity standard tariff charges apply	all non-residential	S	In	n/a	index LMP (with PJM hourly shape)	no	7 PM of previous day for day ahead	http://www.exeloncorp.com/comed/library/pdf/advance_copy_tariff_revision6.pdf	9 customers. 12 MW peak demand; no longer marketed

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Dominion Virginia	Schedule RTP	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (adder on incremental usage) (3) has adders; also has interruptible option	> 5 MW	S	In	yes	lambda	yes	5 PM of previous day	http://www.dom.com/customer/ncbus_rates.jsp	22 customers and 513 MW in 2001; has lost customers, as of 2003 there were 4 customers and 31 MW
Duke Energy Corporation	HP-FLEX	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, symmetrically (3) has adders; also has interruptible option. Has optional pricing baseline separate from CBL.	> 1 MW	P	In	yes	lambda	yes	4 PM of previous day	http://www.dukepower.com/aboutus/rates/ncrates/NCScheduleHPFlex.PDF	53 customers in 2003
Florida Power and Light	RTP-GX	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, symmetrically (3) has adders	> 500 kW	P	In	yes	lambda	no	4 PM of previous day	http://www.fpl.com/about/rates/pdf/electric_tariff_section8.pdf	no longer exists; 20 customers at peak

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Georgia Power	RTP-DA-2, RTP-HA-2	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, symmetrically (3) has adders; also has interruptible option. 2 options: hour ahead and day ahead.	> 250 kW	S	In	yes	lambda	yes	4 PM of previous day for day ahead	http://www.southerncompany.com/gapower/pricing/gpc_pricing_rates.asp?mnuOpco=gpc&mnuType=com&mnuItem=er	1,540 customers as of 2003, with 3250 MW of peak demand; largest in US
Gulf Power	Schedule RTP	1-part energy RTP. (1) all energy charged at RTP, based on utility system lambda (2) has multipliers and adders	> 2 MW	S	In	n/a	lambda	no	4 PM of previous day	http://www.southerncompany.com/gulfpower/pricing/gulf_rates.asp?mnuOpco=gulf&mnuType=com&mnuItem=er#rates	13 customers, 100-150 MW peak demand in 2003
Jacksonville Electric Authority	Schedule RTP	1-part energy RTP: (1) all energy charged at RTP, based on NYISO LMP (2) customer-specific fixed charges based on forecast difference between RTP and std tariff	> 1 MW	S	In	n/a	model	yes	4 PM of previous day	http://www.jea.com/about/pub/downloads/ElectricTariff-LEGAL.pdf	Schedule RTP

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Jersey Central Power & Light (First Energy)	GTX	hybrid RTP + CPP + TOU: (1) on-peak energy charged at PJM hourly RTP (2) off-peak energy charged at PJM off-peak forecast (3) also has utility-designated critical peak periods, 208 hours/year, additional $0.34/kWh plus demand charge	> 10 MW trans mission-level only	P	In	n/a	pool price (PJM LMP)	no	no notification of customer	http://www.firstenergycorp.com:80/customercare/cache/_85256A170068279F_la_NJ+Part+III+20050301__file_tariff _iii_eff030105.pdf	not price responsive, since no advance notification of price; created for a single customer in 1992, and currently has only this customer
Kansas City Power and Light (KCPL)	Schedule RTP	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at an average of RTP and standard tariff, symmetrically (3) has adders	> 500 kW	S	In	no	lambda	yes	4 PM of previous day	http://www.kcpl.com/motariff.pdf	10 customers, 11.2 MW peak demand

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Long Island Power Authority	Voluntary RTP Pilot	1-part energy RTP: (1) all energy charged at RTP, based on NYISO LMP (2) customer-specific fixed charges based on forecast difference between RTP and std tariff	> 145 kW	P	In	n/a	pool price (NYISO)	no	4 PM of previous day	http://www.lipower.org/pdfs/lipatariff.pdf	5 customers, 6 MW peak demand
Niagara Mohawk	RTP (SC3A)	one-part RTP tariff	> 2 MW	S	Default	n/a	lambda			http://www.nationalgridus.com/niagaramohawk/non_html/rates_p sc207.pdf	141 customers > 2MW
Northern States Power (Xcel)	Experimen t al RTP	1-part energy RTP: (1) all energy charged at RTP based on system lambd (2) demand charges (3) has adder	> 1 MW	P	In	n/a	lambda	yes	4 PM of previous day	http://www.xcelenergy.com/XLW EB/CDA/0,3080, 1-14_4531_1743543975_538_9690,00.html	2 customers, 90 MW
Ohio Edison (First Energy)	Experimental Day Ahead RTP Program	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (T&D adder on incremental usage) (3) has adders; also has interruptible option	> 30 kW	P	In	yes	pool price (Cinergy hub)	yes	1 PM day ahead	http://www.firstenergycorp.com/customercare/cache/_85256A170068279F_la_OE+Current__file_OE_2005_PUCO_No11b.pdf	45 customers, 100-200 MW peak demand; not viewed as price responsive, since customers can withdraw on 3 days notice

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
Pennsylvania Power and Light (PP&L)	PR-1(R), PR-2(R)	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, asymmetrically (adder on incremental usage) (3) unbundled GTD adders (4) ancillary service charges	> 2 MW	P	In	yes	pool price (PJM LMP)	yes	5 PM of previous day	http://www.pplelectric.com/NR/r donlyres/2EB170DE-FFF54AED985EF8520ACC0269/0/ratepr1r.pdf	12 customers, 75 MW peak demand as of 2003
PG&E	A-RTP	1-part energy RTP: (1) all energy charged at RTP, originally based on system lambda, then on CALPX prices (2) demand charge based on std tariff (3) has adders	> 500 kW	P	In	n/a	lambda or pool price (CALPX)	no	day-ahead	http://www.pge.com/tariffs/ERS.SHTML#ERS	no longer exists; max of 45 customers, 100 MW peak demand; first RTP in US
Public Service Co of Colorado (Xcel)	PRTP,TRTP, SRTP	2-part RTP: (1) fixed CBL charge (2) difference between actual usage and CBL settled at RTP, symmetrically (3) has adders (4) has separate demand charges based on actual peak demand; also has interruptible option.	> 500 kW	P	In	yes	lambda	yes	4 PM of previous day	http://www.xcelenergy.com/docs/corpcomm/psco_elec_entire_tariff.pdf	expired 2004; max 5 customers

Utility	Program Name	Description of Program or Tariff	Eligibility	Std or Pilot	Opt-In or Default	Adjustable CBL?	Source of Hourly Price	Interrupt Option (Y/N)	Time of Price Signal	Tariff Web Site	Notes
SCE	RTP-2	1-part energy RTP. (1) all energy charged at RTP, based on synthetic, temperature based simulation model (2) has unbundled T&D charges standard tariff charges apply	> 500 kW	S	In	n/a	model (temperature based marginal cost model)	yes	day ahead	http://www.sce.com/AboutSCE/Regulatory/tariffbooks/ratespricing/	no longer open, methodology obsolete; currently 96 customers, 136 MW peak demand
SDG&E		1-part energy RTP. (1) all energy charged at RTP, (2) has unbundled T&D charges	> 100 kW	P	In	n/a	index LMP (SP15)	no	5 PM of previous day	http://www.sdge.com/regulatory/tariff/current_tariffs.shtml	
Wisconsin Electric Power Co (WE Energies)	Experimental RTP	1-part energy RTP: (1) all energy charged at RTP based on system lambda (2) demand charges (3) MGCC adder	> 500 kW	P	In	n/a	lambda	yes	4 PM of previous day	http://www.weenergies.com/business_new/elec/elecrateswi.htm	no current customers

Table B.8. DLC Programs Offered by US and International Utilities

Utility	Program Name	Description of Program and Customer Incentives	Std/Pilot	Vol/Man	Opt-In/ Opt-Out	Max Pay $/Mon	Pay Per Event $	Addl Cust Charge $/Mon	Tariff Web Site	Notes
Allegheny Power	Electricity Price Response Pilot Program	Utility and customer share control of heating and air conditioning loads via internet-based smart thermostat, with customer having ability to override utility DLC in response to RTP signal. Customers paid monthly incentive + per hour for reductions.	P	V	In	?	?	0.00		300 customers in pilot program. Program no longer exists.
Baltimore Gas and Electricity (BGE)	Energy Saver Switch	Utility direct control over A/C cycling using remote switch, 15 minutes on and 15 minutes off, at any time during year. Customer incentive bill credit $10/month June-September.	S	V	In	10.00	0	0	http://www.bge.com/CDA/Files/EnergySaverSwitch.pdf	300,000 participants, 350 MW
Commonwealth Edison	Rider AC	Utility directly control over A/C and pool pumps using remote switch. Cycles for up to 8 hours per day during summer, a maximum of 20 days. 2 options for cycling time (50% and 100%), without and without pool pump. Customer receives bill credit of up to $12.50 per month.	S	V	In	12.50	0	0.00	http://www.exeloncorp.com/comed/library/pdfs/0_ratebook.pdf	

Utility	Program Name	Description of Program and Customer Incentives	Std/Pilot	Vol/Man	Opt-In/ Opt-Out	Max Pay $/Mon	Pay Per Event $	Addl Cust Charge $/Mon	Tariff Web Site	Notes
Detroit Edison	Interruptible Space Conditioning (D1.1)	Utility directly control over A/C and water heaters using remote switch. Cycles 30 min on, 30 min off intervals for up to 8 hours per day, no limit on number of days. Pay-per-event bill credit for interruptions ($4 per day), no monthly bill credit.	S	V	In	0	4.00	1.95	http://my.dteenergy.com/myAccount/pdfs/detroitEdisonTariff.pdf	
Dominion Virginia	Rider J	Utility directly controls electric water heater with remote switch, cycles up to 8 hours per day year-round. Customer receives $4/month bill credit.	S	V	In	4.00	0	0	http://www.dom.com/customer/pdf/va/riderj.pdf	
Florida Power and Light	On Call	Utility directly controls customer-specified devices through EMS system, with 2 levels of incentives based on cycling time (from 15 minutes to 4 hours) for each of 4 types of devices (AC, heating, water heating, pool pump) on seasonal basis. Combined incentives produce bill credit of up to $162/year.	S	V	In	13.50	0	0	http://www.fpl.com/home/services/contents/residential_on_call.shtml	700,000 participants, over 700 MW
Florida Power Corp (Progress Energy)	Energy Management Program	Utility cycles heating and water heating during winter months through EMS system. Up to $11.50 per month bill credit, prorated for usage above 600 kWh.	S	V	In	11.25	0	0	http://www.progressenergy.com/custservice/flares/energymgmt/EM_Flyer_RSL_2.pdf	470,000 participants with 470 MW

Utility	Program Name	Description of Program and Customer Incentives	Std/Pilot	Vol/Man	Opt-In/ Opt-Out	Max Pay $/Mon	Pay Per Event $	Addl Cust Charge $/Mon	Tariff Web Site	Notes
Idaho Power	Schedule 81	Utility directly controls customer air conditioner using remote switch, cycles up to 4 hours per day, 40 hours per month, 120 hours per season, which is June-August. Customer receives $7/month bill credit.	S	V	In	7.00	0	0.00	http://www.idahopower.com/aboutus/regulatoryinfo/tariffPdf.asp?id=243&.pdf	
Indianapolis Power and Light Co (IPALCO)	Rider 13	Utility directly controls customer air conditioner using remote switch, unlimited days and hours, May-September. Customer receives $5/month bill credit.	S	V	In	5.00	0	0.00	http://www.ipalco.com/download/riders.pdf	
Ohio Edison (First Energy)	Controlled Service Riders	Utility directly controls electric water heater and heat pumps using equipment installed at customer expense. Provides lower rates in return for unlimited days of interruption, up to 8 hours per day.	S	V	In	0.00	0	0.00	http://www.firstenergycorp.com/customercare/cache/_85256A170068279F_la_OE+Current__file_OE_2005_PUCO_No11b.pdf	
Northern States Power (Xcel)	Saver's Switch	Utility direct control over A/C cycling using remote switch, 15 minutes on and 15 minutes off, for a maximum of 300 hours per year; turns off water heater for up to 6 hours per day. Customer receives 15% off of energy charges June through September for A/C, additional 2% for water	S	V	In	15.00	0	0	http://www.xcelenergy.com/XL WEB/ DA/0,3080,112_738_177192135_538_ 9690,00.html	350,000 participants, over 250 MW

Utility	Program Name	Description of Program and Customer Incentives	Std/Pilot	Vol/Man	Opt-In/ Opt-Out	Max Pay $/Mon	Pay Per Event $	Addl Cust Charge $/Mon	Tariff Web Site	Notes
Potomac Electric Power (PEPCO)	Kilowatchers	Utility controls air conditioners, heat pumps, and water heaters via EMS system. Two levels of incentives based on cycling time, with monthly bill credits May through September, plus per event payments.	S	V	In	?	?	0	http://www.pepco.com/hm_dc_kilowatchers.htm	162,000 participants , over 200 MW; program suspended as of 2005
SCE	Summer Discount	Utility directly controls A/C cycling using remote switch. Customer receives monthly bill credit based on 3 levels of cycling, each with 2 options for number of interruptions (max of 15, or unlimited), and the A/C tonnage. Credits range from $0.10-$0.36/ton-day.	S	V	In	36.00	0	0	http://www.sce.com/RebatesandSavings/Residential/SummerDiscountPlan/Details/default.htm	200,000 participants, 280 MW. Monthly credit calculation based on 4-ton central A/C.
SMUD	Peak Corps	Utility controls customer A/C cycling using remote switch, June 1 to September 30. 3 levels of incentive based on cycling time. Monthly credit + per event payment, ranging from $2.50/month + $1/cycle day for 27 min/hr, up to $5/month + $3/cycle day for 60 min/hr.	S	V	In	5.00	3.00	0	http://www.smud.org/residential/saving/peak.html	100,000 participants
Wisconsin Public Service (WPD)	HELP	Utility controls cust air conditioners and water heaters using remote switch.	S	V	In	8.00	0	0	http://www.wisconsinpublicservice.com/home/help.asp	

Table B.9. DSS Programs Offered by US and International Utilities

Utility	Tariff Name	Description of Program or Tariff	Std or Pilot?	Default or Opt-In?	Customer Incentive $/kW-Month	Addl Customer Charge ($)	Tariff Web Site	Notes
ACEA-Electrabel	Uso Abitazione	Customer-chosen demand level plus flat rate service. The chosen demand level cannot be physically exceeded due to demand limiter.	S	Default	0	0	http://www.aceaelectrabelelettricita.it/aceaelectrabel_elettricita/sportello/contratti.asp?name=tariffe_uso_domestico.html	
Electricidade de Portugal	Tarifa bi-horaria	Customer-chosen demand level (3.45 to 20.7 kW in 10 increments) + 2 period, year-round TOU energy rate.	S	Opt-in	0	2.74	http://www.edp.pt/indexasp?CID=402300&LID=pt&MID=1&OID=3010000&PID=3000000&SESSID=o50B00I20s00x07F1W5q4Ds	Customer charge for 3.45 kW, relative to flat tariff
Electricidade de Portugal	Tarifa tri-horaria	Customer chosen demand level (3.45 to 20.7 kW in 10 increments) + 3 period, year-round TOU energy rate.	S	Opt-in	0	4.91	http://www.edp.pt/indexasp?CID=402300&LID=pt&MID=1&OID=3010000&PID=3000000&SESSID=o50B00I20s00x07F1W5q4Ds	Customer charge for 3.45 kW, relative to flat tariff
Electricite de France	L'option base w/ 5 sub-options	Customer chosen demand level (3 to 36 kVA) + flat rate service.	S	Default	0	0	http://particuliers.edf.fr/rubriq ue114.html	
Electricite de France	L'option heures creuses w/ 5 sub-options	Customer-chosen demand level (6 to 36 kVA) + 2 period, year round TOU	S	Opt-in	0	5.00	http://particuliers.edf.fr/rubriq ue114.html	Customer charge for 6 kW, relative to flat tariff

Utility	Tariff Name	Description of Program or Tariff	Std or Pilot?	Default or Opt-In?	Customer Incentive $/kW-Month	Addl Customer Charge ($)	Tariff Web Site	Notes
Electricite de France	L'option Tempo	Demand subscription (9 to 36 kVA) + CPP with 2 period TOU energy rate for each of 3 categories of usage days: 300 blue days, 43 white days, 22 red days. White and red days called by utility day-ahead. Red days all fall within the period Nov 1-Mar 31.	S	Opt-in	0	4.77	http://particuliers.edf.fr/rubriq ue112.html	Customer charge for 9 kW, relative to flat tariff
ENEL SPA	Tariffa Una	Customer chosen demand level (3-15 kVA) + flat tariff.	S	Default	0	0	http://www.enel.it/sportello_online/elettricita/tariffe_elettriche/tariffe_due_costi.asp	
ENEL SPA	Tariffa Bioraria w/ 3 sub-options	Customer chosen demand level (3-15 kVA) + 2 period, year-round TOU	S	Opt-in	0	5.60	http://www.enel.it/sportello_online/elettricita/tariffe_elettriche/tariffe_due_costi.asp	
Tokyo Electric Power Co (TEPCO)	Meter Rate Lighting (A or B)	Customer-chosen demand level plus flat rate service. The chosen demand level cannot be physically exceeded due to demand limiter.	S	Default	0	0	http://www.tepco.co.jp/en/service/custom/guide/guide04e.html	
SCE	Demand Subscription Service	Customers subscribe to a level of demand less than their calculated level, in return for monthly bill credit during summer months.	P	Opt-in	5.00			Pilot program from 1983 to 1987, no longer exists

Appendix C: Source Material on Empirical Estimation of Customer Response to TOU Pricing and Demand Response Programs

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