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How to Induce Customers to Consume Energy Efficiently:

Rate Design Options and Methods

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Online Access

This paper can be found online at www.nrri.org/pubs/electricity/NRRI_inducing_energy_efficiency_jan10-03.pdf.

Executive Summary

Utilities and their regulators view a different world than the one their customers perceive. In the world seen by most electricity customers, electricity costs the same amount regardless of how much is used or when. In contrast, utilities and their regulators see a world where electricity costs vary by the hour, infrastructure investments loom, and new or upcoming legislation requires reductions in electricity consumption or carbon emissions. "Efficiency-inducing rates (EIRs)"—defined here as rates that vary by time, condition, or customer behavior in order to induce efficient electricity consumption—bridge this perception gap. By aligning rates with electricity costs, they encourage customers to use electricity when it is least costly and lower their overall consumption.

This report seeks to empower regulators to evaluate and propose EIRs or effectively scrutinize utility proposals. It examines EIR options including inclining block rates, seasonal rates, time-of-use rates, critical peak pricing programs, and real-time pricing. On October 27, 2009 the federal government provided $3.4 billion of grants to 100 "smart grid" projects. Most smart grid projects include deployment of advanced meters, which facilitate certain EIRs. Regulators should evaluate rate options to maximize smart grid benefits.

Each EIR features unique advantages, disadvantages, and design choices. Certain decisions, such as who is eligible and whether rates are mandatory, apply to all EIRs. Additionally, some EIRs can operate in conjunction with others. Because regulators do not make rate design decisions in a vacuum, this report also explains how various EIRs affect different customer classes and how they complement or detract from distributed renewable energy development.

This report also guides regulators step-by-step through the process of crafting seasonal and time-of-use rates, which will also enable scrutiny of utility rate proposals. For instance, it describes how to select the optimal number of seasons and time periods, how much rates should vary between periods, and how to estimate customer behavioral changes in response to new EIRs. Many of the discussed processes and principles for fashioning time-of-use rates also apply to designing other EIRs.

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Part One

Efficiency-Inducing Rates: Evaluation and Implementation

Introduction

Faced with increasing generation costs and environmental goals or mandates, regulators are examining methods to induce customers to consume electricity more efficiently by reducing both their aggregate and peak consumption. Some utilities also face capacity margin shortfalls, which could degrade reliability without new generation or transmission investments. "Efficiency Inducing Rates (EIRs)" address these challenges by encouraging customers to **reduce peak demand and overall consumption**. Thus regulators are using economic levers to optimize customer behavior.[1]

We define EIRs as rates that vary by time, condition, or customer behavior in order to induce efficient electricity consumption.[2] They include **inverted block rates**, **seasonal rates**, **time-of-use (TOU) rates**, **critical peak pricing (CPP)**, and **real-time pricing (RTP)**.

This paper informs regulators about EIR options and their consequences. It will assist them in either designing rates or evaluating utility proposals. It provides examples and discusses what data and methodologies regulators should use to design or evaluate rates. Such rates maximize the value of smart grid technologies, including those funded through federal grants.

Part One, Section I discusses rate design goals and efficiency implications. It also describes each EIR, including potential benefits, costs or concerns, and unique design decisions. Section II explores common design decisions, such as whether rates are mandatory or optional, that commissions confront when designing all EIRs. Section III examines how different EIRs could overlap with each other. Finally, Section IV describes how EIRs affect different customer groups and how they enhance or diminish the economic value of distributed renewable energy projects.

Part Two explains how to craft seasonal/TOU rates. Certain principles and practices addressed in Part Two, such as the use of estimates of elasticities of demand, also apply to evaluating other EIRs.

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[1] For more discussion on encouraging but not mandating optimal behavior, please see *Nudge* by Richard Thaler and Cass Sunstein and see Scott Hempling's essay "Decisional Defaults: Does Regulation Have Them Backwards?" at http://www.nrri2.org/index.php?option=com_content&task=view&id=179&Itemid=38

[2] EIRs include "dynamic rates" such as real-time and critical peak pricing rates as well as other non-flat rate designs.

Table 1. Efficiency-Inducing Rate Options

Inclining block rates: Rates that increase at higher levels of electricity consumption
Seasonal rates: Rates that vary by season
Time-of-use rates: Rates that vary by time of day and day of the week
Critical peak pricing: Programs allowing the utility to dramatically increase rates on short notice a predetermined number of times per year
Real-time pricing: Rates that adjust in real-time based on wholesale electricity costs

I. Introduction to Efficiency-Inducing Rates: What Are Their Purposes, Their Benefits, and Their Risks?

A. Rate design overview

1. Rsate design goals

The two primary goals of rate design are to (a) provide rates that lead to utility **revenues matching the revenue requirement** and (b) **allocate both fixed and variable costs** to responsible customers. Effective rate designs also:

1. **Minimize complexity**, recognizing differing degrees of customer sophistication;
2. Maximize cost **predictability and stability** for customers and revenue certainty for utilities;
3. Incent utilities to **minimize costs**; and
4. Incent customers to **consume electricity efficiently** by minimizing peak demand and/or total consumption.

Rate designs in some jurisdictions also seek to:

1. Improve electricity **affordability** for poor or vulnerable populations ("lifeline rates");
2. Promote **economic development**, often by providing lower rates for industrial customers; and
3. Maximize **customer choice**.

When evaluating EIRs, regulators should examine their consequences for the two primary rate design goals and for the secondary rate design goals. Regulators must determine whether improvements in the effectiveness of rates in some regards due to changes in rate design outweigh corresponding reductions in other forms of rate design effectiveness.

2. Rate design and efficiency

Traditional rate designs featuring a combination of fixed charges and variable charges based on constant per-kWh rates do not reflect the actual costs of electricity. Such costs differ based on the time-of-day, season, transmission and generation availability, and other factors.[3] Traditional rate designs do not reflect these variations beyond fuel cost adjustment charges, which at best reflect only seasonal changes in fuel costs and are often subject to substantial regulatory lag. Thus, while the utility's cost of electricity in peak summer hours could be $0.50 per kWh, the energy component of the customer's rate could be $0.10 per kWh, the same as it is when electricity cost the utility $0.04 per kWh during the off-peak hours of shoulder months.

Further, some rate designs *discourage* energy efficiency. Certain utilities offer rates that decrease with higher consumption. Such rates often reflect the variable (energy) rate component including fixed costs, causing average electricity costs to exceed marginal electricity costs.

By contrast, EIRs align customer behavior with the actual cost of electricity. Except for inclining block rates, which encourage customers to minimize overall rather than peak consumption, EIRs encourage efficient consumption. Savings from energy efficiency come in two primary forms: (1) **reduced electricity and capacity costs** and (2) **delayed or avoided infrastructure investments.**

Regional transmission organizations (RTOs) and utilities dispatch generation in order of increasing costs, subject to reliability constraints. In most **organized markets**, the last generator dispatched sets the price for all electricity sales.[4] Consequently, dispatch of expensive generators increases the average cost *paid* for electricity far more than the average costs of *producing* electricity. Conversely, reducing peak demand, and thus the use of expensive units, provides large savings by reducing payments to all other units. The following graph from the 2008 State of the Markets Report for PJM illustrates that the cost of electricity in PJM increases steeply after regional demand exceeds approximately 160,000 MW. Thus, even small reductions in peak demand during those peak hours could substantially lower aggregate costs.

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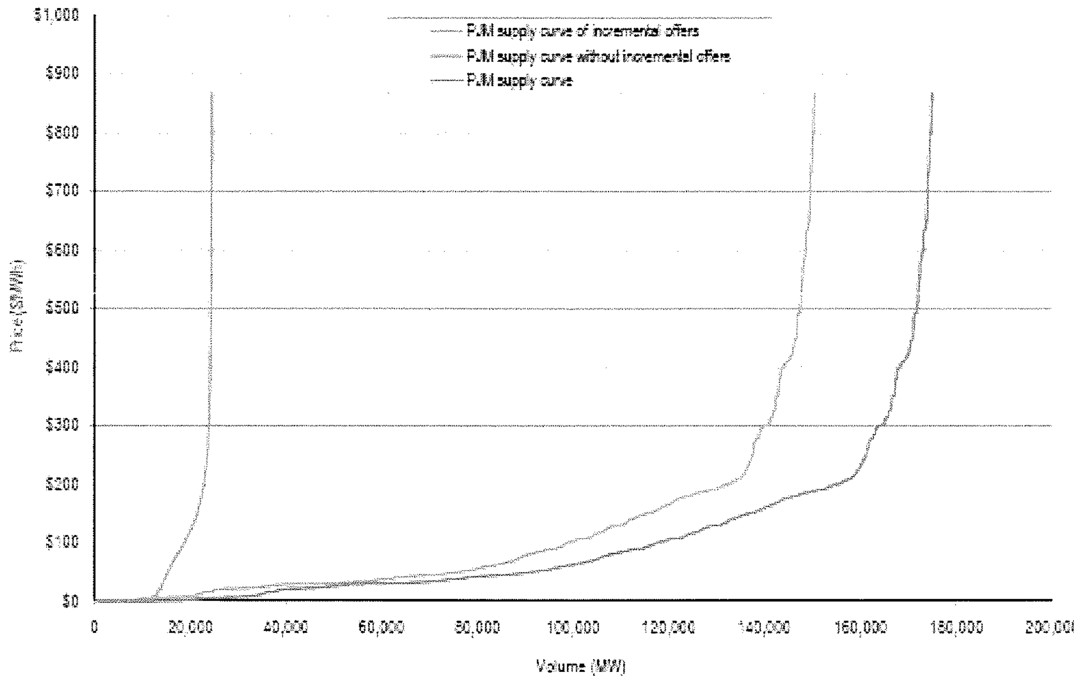
[3] Peak real-time spot market electricity costs can exceed average costs by more than tenfold. *See* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008/2008-som-pjm-volume2-sec2.pdf.

[4] Most regional transmission organizations operate wholesale electricity markets that feature a single market-clearing price.

Figure 2-16 PJM day-ahead aggregate supply curves: 2008 example day



Traditionally regulated utilities receive smaller short-term savings from peak demand reductions than do utilities who acquire electricity through organized markets. Customers of traditionally regulated utilities pay the same depreciation and returns on utility-owned generators, regardless of energy costs. Such utilities also pass through *total* energy costs to customers, so reductions in peak demand do not affect the costs paid for all wholesale electricity.

Aside from reducing the dispatch of the most expensive units, peak demand reductions allow utilities to defer transmission and distribution upgrades as well as new generation capacity because systems must accommodate peak demand. Long-run marginal cost calculations consider the capital costs of serving additional load. Avoided infrastructure savings from EIRs, while potentially large, would not be immediate because the avoided investments would not enter rate base for some time and would depreciate over a long period.

In organized markets, long-run savings come from avoided transmission and distribution investments and lower capacity payments. The savings from avoiding infrastructure development are larger for customers of traditionally regulated utilities. There, the savings come from avoided transmission or distribution *and* avoided generators (peaking or base load), which would otherwise increase utility rate bases and thus rates.[5]

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[5] RTOs through planning and price signals, elicit the development of transmission and distribution infrastructure as well as new generation capacity. However, certain writers, state

EIRs optimize electricity consumption by encouraging **load shifting** and **reductions in total consumption** because rates reflect actual electricity costs. Some customers can shift their consumption to hours or even seasons that are less expensive. For instance, customers with TOU rates could wash clothes at night instead of during the day. Certain EIRs also can incent customers to minimize overall electricity consumption. For instance, inclining block rates render electricity more expensive at higher consumption levels, encouraging customers to keep their consumption below block thresholds.

B. Inclining block rates

1. Description

Inclining block rates, sometimes called inverted block rates or baseline rates, feature one per-kWh rate for the first monthly kWh block of consumption and higher rates for each subsequent block. These rates best suit residential customers. Their consumption is more predictable than commercial, industrial, or agricultural customers, whose size and electricity needs vary marked, inhibiting identifying optimal block sizes. Unlike other EIRs, inclining block rates are usually mandatory rather than optional.

Inclining block rates can motivate customers to reduce consumption to attainable levels. Incentives to improve energy efficiency increase for heavy users of electricity but diminish for customers who already consume little electricity. Inclining block rates do not encourage load shifting because they disregard consumption timing.

The following example from PNM features three rate blocks. PNM couples inclining block rates with seasonal rates.[6]

IN THE BILLING MONTHS OF:	June, July and August	All Other Months
(A) CUSTOMER CHARGE: (Per Metered Account)	$4.00/Bill	$4.00/Bill
(B) ENERGY CHARGE:		
First 200 kWh per Month	$0.073254/kWh	$0.073254/kWh
Next 500 kWh per Month	$0.105918/kWh	$0.095684/kWh
All Additional kWh per Month	$0.131829/kWh	$0.099206/kWh

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commissions, and legislatures, such as Maryland's, have found that RTOs do not send accurate price signals to prospective builders of additional capacity.

[6] http://www.pnm.com/regulatory/pdf_electricity/schedule_1_a.pdf

2. Benefits

Inclining block rates induce energy efficiency measures such as efficient heating and air conditioning systems and improved insulation. They can also encourage distributed generation, such as solar panels. Such measures reduce overall energy consumption. Inclining block rates help utilities meet consumption reduction obligations or carbon emissions legislation. According to one study, inclining block rates provide energy consumption savings of six percent for the first few years and more over the long run.[7] Unlike critical peak pricing and real-time pricing, inclining block rates do not necessitate any additional infrastructure, such as advanced metering infrastructure (AMI).

3. Costs and concerns

Poor families with large but old homes could see higher bills under inclining block rates but lack the ability to respond to the price signals. Regulators should examine the availability of federal, state, and utility low-income weatherization programs, which can mitigate this problem.

For certain customers, inclining block rates reduce energy efficiency incentives. For instance, customers whose monthly consumption already falls within the lower block(s) would see lower electric bill savings from energy efficiency measures or distributed generation under inclining block rates than they would under traditional rates.

Inclining block rates could encourage certain customers to switch their water and heating from electricity to natural gas in order to avoid consumption in costlier blocks. This practice would not reduce overall energy consumption; rather, it would just encourage use of another energy source. Thus, this rate design could favor gas-powered appliances or heating systems, allowing customers to reduce utility bills without becoming more energy-efficient—at the expense of other customers.

Rates that reduce overall energy consumption diminish utility sales and thus revenues. The level of reduced consumption is uncertain, increasing the risk of revenues falling below the revenue requirement established in rate cases. Such uncertainty could degrade utility credit ratings and their ability to access capital. Inclining block rates also increase rate complexity for customers.

4. Programmatic decisions

How many blocks? Most inclining block rates feature two to five rate blocks.[8] This range presents customers with identifiable consumption goals. One suggested structure includes

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[7] Faruqui, Ahmad, "Inclining Towards Efficiency," *Public Utilities Fortnightly*, August 2008, page 25.

[8] Pacific Gas and Electric Company features five tiers for its inclining block rates. http://www.pge.com/myhome/customerservice/financialassistance/medicalbaseline/understand/

four blocks. The lowest block's rate aligns with the embedded costs of the system, the second block's rate reflects the average system costs, and the top two blocks' rates reflect the utility's long-run marginal costs of service.[9]

What should be the kWh cutoff between blocks? Inclining block rates should encourage *most* customers to reduce their electricity consumption to attainable levels. If most customers would see lower peak rates under inclining block rates without changing their consumption, the rates would not encourage energy efficiency. The summer PNM rate example above features cutoff between the second and third tiers of 500 kWh. The average PNM customer consumes 600 kWh per month.[10] Thus, rates encourage most customers to reduce consumption by 100 kWh, a meaningful but attainable goal. In California, the Public Utilities code requires that baseline quantities (the lowest tier) fall between 50 and 60 percent of average use for basic-electric customers in both the summer and winter and for all-electric and gas customers in the summer. The PU code also requires that, in the winter, baseline quantities fall between 60 and 70 percent of average use for all-electric and gas customers.[11]

How much should rates differ between blocks? Large rate differences between blocks increase the energy efficiency incentives for high-consuming customers. Conversely, large differences reduce the energy efficiency incentives for low-consuming customers. Large differences could also cause certain customers to pay far more than the actual cost of their electricity, running counter to the second primary goal of rate design shown in I(A): "Allocate both fixed and variable costs to responsible customers."

Inclining block rates should reflect cost causality, specifically **long-run marginal costs**. In other words, high-use customers who place greater long-run costs on the system should pay accordingly. Such customers necessitate additional transmission, distribution, and generation investments. Such customers' rates should reflect the long-run marginal costs of electricity use, even if the short-run marginal cost of supplying customers decreases as consumption goes up.

Should inclining block rates consider household characteristics? Larger families are likely to consume more electricity than smaller ones. Block sizes could differ based on customer household size because reasonable consumption for a single person is different than for a large family. Such a policy would increase administrative cost, however. As an example of differentiating rates based on customer characteristics, Pacific Gas and Electric's baseline rates

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Puget Sound Energy features two blocks.
http://www.pse.com/SiteCollectionDocuments/rates/summ_elec_prices_2009_04_01.pdf

[9] http://www.psc.state.ut.us/utilities/electric/07docs/0703593/61949ExhibitD.ppt#273,4,RESIDENTIAL USAGE OF ELECTRICITY

[10] See PNM press release: http://www.pnm.com/news/2009/0528_rates_approved.htm

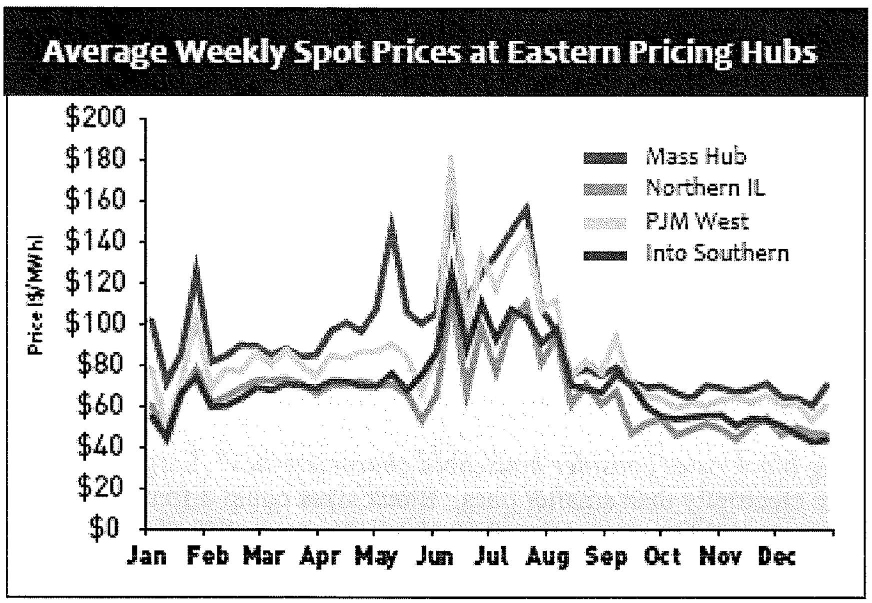
[11] http://www.pge.com/myhome/customerservice/financialassistance/medicalbaseline/understand/

feature an exception for persons with medical conditions requiring equipment or special heating/cooling needs.[12] PG&E's baselines and thus blocks also differ within utilities by region to account for weather differences.[13]

C. Seasonal rates

1. Characteristics

Seasonal rates reflect the high average cost of electricity during the winter or summer. They typically feature two seasons and often combine with TOU rates. Seasonal rates suit regions with distinct seasonal variations in electricity demand and costs. The graph below shows the average weekly electricity spot prices at four Eastern trading hubs, as reported in the 2008 FERC State of the Markets Report.[14] Each hub features a summer peak and two also feature winter peaks.



Source: Derived from Platts data.

The following example of seasonal rates from Public Service Company of Colorado applies to commercial customers.[15]

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[12] http://www.pge.com/myhome/customerservice/financialassistance/medicalbaseline/

[13] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf

[14] http://www.ferc.gov/market-oversight/st-mkt-ovr/st-mkt-ovr.asp

[15] http://www.xcelenergy.com/SiteCollectionDocuments/docs/psco_elec_entire_tariff.pdf

MONTHLY RATE	
Service and Facility Charge:	$ 7.85
Energy Charge:	
All kilowatt-hours used, per kWh	
Summer Season	0.03497
Winter Season	0.03120
The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.	
MONTHLY MINIMUM	$ 7.85

2. Benefits

In response to seasonal rates, certain customers, such as large industrials, can shift some of their electricity consumption to off-peak months. Such shifts reduce utility peak demand and thus overall system costs by reducing dispatch of the most expensive generators and forestalling system upgrades.

A majority of customers cannot shift their load between seasons. Instead, seasonal rates encourage consuming less electricity and pursuing energy efficiency measures during the peak seasons. For instance, higher summer rates incent investment in high-efficiency air conditioners, lowering overall consumption and carbon emissions. Such resulting efficiency measures to some extent decrease peak demand as well.

Although more complicated that flat rates, seasonal rates are **predictable**, unlike critical peak pricing or real-time rates, such that unsophisticated (*e.g.*, residential) customers do not need to follow rates. Finally, seasonal rates do not necessitate infrastructure expenditures such as advanced meters.

3. Costs and concerns

Customers who are unable to readily shift their load to off-peak seasons or reduce their overall consumption could face higher overall electricity bills. Seasonal rates also increase rate complexity. Additionally, as discussed in section I.B.3, rate designs that affect consumer behavior increase utility risk of revenue under-recovery.

4. Programmatic decisions

Part Two provides practical guidelines for how to approach these decisions.

Which seasons should be peak and off-peak? Certain regions, like the Southwest, feature prominent summer peaks in both demand and wholesale electricity costs. Others, such as the Midwest, include summer and winter peaks. Certain states, such as Hawaii, feature low variation between seasons. To determine whether peak rates should be in the summer, winter, both, or neither, examine utilities' average monthly peak demand and average electricity costs.

What should be the duration of peak seasonal periods? Determine the timing and duration of peak periods based on utilities' average monthly peak demand and electricity costs.

How large should the discrepancy be between rates for peak and off-peak seasons? Large differences between seasonal rates increase incentives to shift or reduce consumption. They also reduce incentives to conserve electricity in off-peak seasons. Regulators should base rate differentials on variations in average wholesale electricity costs.

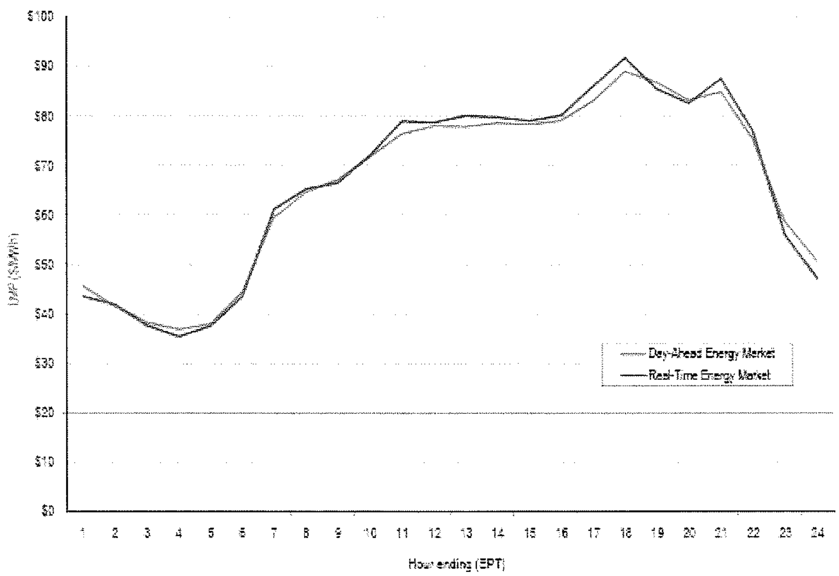
D. Time-of-use rates

1. Description

Time-of-use rates feature different rates at different hours of the day and days of the week. TOU rates include peak and off-peak rates and, in some cases, mid-peak rates for shoulder hours. Weekends and holidays are usually off-peak. TOU rates often combine with seasonal rates.

The graph below from the 2008 State of the Markets Report for PJM illustrates the variation between average locational marginal prices during different hours.[16] Individual seasons or days of the week can feature larger variations.

Figure 2-19 PJM system hourly average LMP: Calendar year 2008



[16] Locational marginal price (LMP): Used in certain organized markets, the LMP is the cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits.

Below is an example of residential TOU rates from the Connecticut Light and Power Company.[17]

MONTHLY RATE:

ON-PEAK (Weekdays 12 Noon - 8 p.m. during Eastern Standard Time)
(Weekdays 1 p.m. – 9 p.m. during Daylight Savings Time)

OFF-PEAK (All other hours)

DISTRIBUTION SERVICE RATE:

CUSTOMER CHARGE	$350.00
DIST. DEMAND CHARGE	$5.42 per kW

TRANSMISSION SERVICE RATE:

PROD./TRAN. DEMAND CHARGE	$2.45 per kW
CHARGE PER KWH ON-PEAK	$0.01492
CHARGE PER KWH OFF-PEAK	$0.00342

SUPPLIER SERVICE OPTIONS:
(as per the Generation Services tariff)

GENERATION SERVICE: STANDARD SERVICE
(MAX DEMAND LESS THAN 500 KW)

CHARGE PER KWH ON-PEAK	$0.14327
CHARGE PER KWH OFF-PEAK	$0.11327

2. Benefits

Unlike seasonal rates, TOU rates enable most customers to shift consumption away from peak periods. For instance, customers can wash clothes and dishes at night. Such shifts reduce peak demand and thus overall electricity costs and avoid infrastructure investments.

Where customers cannot shift their consumption, TOU rates can encourage lower total consumption and energy efficiency measures. For instance, TOU rates incent customers to raise their thermostats during peak, summer hours, but few customers respond by using their air conditioners *more* during off-peak, night hours.[18]

TOU rates are predictable, unlike critical peak pricing or real-time rates, such that unsophisticated customers can participate without following price signals.

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[17] http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/rate37/$File/rate37.pdf

[18] TOU rates lower rates during off-peak periods. It is possible that the lower rates during these periods will reduce energy efficiency incentives such that aggregate consumption does not fall compared to flat rates.

3. Costs and concerns

TOU rates can increase electricity costs for certain customers, such as retail stores, whose consumption falls heavy during peak periods but cannot be readily reduced or shifted.

TOU rates can require the installation of new meters capable of recording when customers consume electricity and bill them accordingly. TOU rates also feature greater complexity than do flat rates. Finally, as discussed in section I.B.3, rate designs that affect consumer behavior increase utility revenue uncertainty.

4. Programmatic decisions

Regulators must address the following programmatic discussions, which Part Two describes in more detail and provides practical solutions for.

How many tiers should TOU rates include? Most TOU rates include two or three rate tiers. TOU rates with mid-peak rates often better align the costs of electricity with retail rates than do two-tier rates. Such precision comes at the cost of added complexity, however. Regulators should examine fluctuations in average hourly wholesale electric costs. Where average wholesale costs bifurcate neatly between peak and off-peak periods, mid-peak rates are unnecessary. Mid-peak rates could also cover weekends and holidays, which often feature usage lower than normal weekdays but higher than nights.

What should be the peak, mid-peak, and off-peak hours? TOU rates should correlate to average hourly electricity costs. Regulators should examine average electricity costs for different hours and days over multiple years to control for weather fluctuations.

How much should peak, mid-peak, and off-peak TOU rates differ? Larger rate differences lead to high incentives to shift or reduce consumption. They also reduce incentives to conserve during off-peak periods. Further, large differentials increase bills for customers whose consumption takes place heavily on-peak and who cannot readily shift or reduce consumption. Regulators should base TOU rates on the differences in the wholesale electricity costs during different times of day or days of the week to align rates signals with costs.

E. Critical peak pricing

1. Description

Critical peak pricing (sometimes called "dynamic peak pricing") programs allow the utility to increase rates on short notice (often one day) for a defined period (often several hours) a certain number of times a year (*e.g.*, 10). In exchange, participating customers receive rate discounts during other periods. Most utilities enjoy wide discretion to call critical peak events based on economic or reliability considerations. CPP programs often combine with TOU rates.

CPP programs differ from certain RTO economic demand response programs, which credit customers for reducing demand at certain times but do not change rates. Also, unlike certain demand response programs in which the utility can control customer loads, CPP participants can continue consuming electricity, though at high rates.

Peak time rebate (PTR) programs, though not technically rates, provide an alternative to CPP programs with similar costs and benefits. PTR programs provide a rebate against customers' electricity bills if they reduce consumption in critical events compared to their baseline consumption. They do not change their electricity rates. Unlike some CPP programs, customer bills cannot increase under PTR programs compared to flat rates if they do not reduce consumption. This lack of customer risk could improve participation rates for peak time rebate programs compared to CPP programs.

Baltimore Gas and Electric Company has conducted pilots for CPP and PTR programs and Xcel Energy proposed to offer both programs for certain Colorado customers.[19, 20] Baltimore Gas and Electric found that customer satisfaction was higher for PTRs than CPP despite similar reductions in peak demand.[21] Customers found peak time rebates easier to understand and most supported PTR as the default rates and not CPP rates.

The discount from CPP programs tends to come from the energy component of rates during other hours, reducing energy efficiency incentives. Contrastingly, the customer benefits from PTR programs do not lower rates at other times, thus maintaining energy efficiency incentives during other hours.

The following example of Critical Peak Pricing, combined with TOU and seasonal rates, is from Portland General Electric Company's residential CPP pilot.[22]

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19 www.bgesmartenergy.com/media/ses/SESP%20Fact%20Sheet.doc

20 http://www.dailycamera.com/boulder-county-news/ci_13732272

21 www.demandresponsetownmeeting.com/.../Cheryl%20Hindes%20**BGE**_SESSION%20A,%207.14.09.ppt

22 http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_012.pdf

<u>Basic Charge</u>

Single Phase Service	\$10.00	
Three Phase Service	\$13.00	
<u>Transmission and Related Services Charge</u>	0.212	¢ per kWh
<u>Distribution Charge</u>	2.897	¢ per kWh
<u>Energy Charge</u>		
Off-Peak Period	5.580	¢ per kWh
On-Peak Period	7.080	¢ per kWh
Critical Peak (when called)	33.480	¢ per kWh

* See Schedule 100 for applicable adjustments.

ENERGY CHARGE TIME PERIODS

Summer Hours (May 1 – October 31)

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="12">PM</td></tr>
<tr><td colspan="24">1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11</td></tr>
<tr><td>Standard Day
Mon. - Sat.</td><td colspan="14">Off Peak</td><td colspan="8">On Peak</td><td colspan="2">Off Peak</td></tr>
<tr><td>Load Reduction Day
(when called*)</td><td colspan="14">Off Peak</td><td colspan="2">On Peak</td><td colspan="4">Critical Peak</td><td colspan="2">On Peak</td><td colspan="2">Off Peak</td></tr>
<tr><td>Sundays and
Holidays**</td><td colspan="24">Off Peak</td></tr>
</table>

Winter Hours (November 1 – April 30)

<table>
<tr><td rowspan="2"></td><td colspan="12">AM</td><td colspan="12">PM</td></tr>
<tr><td colspan="24">1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11</td></tr>
<tr><td>Standard Day
Mon. - Sat.</td><td colspan="7">Off Peak</td><td colspan="4">On Peak</td><td colspan="7">Off Peak</td><td colspan="4">On Peak</td><td colspan="2">Off Peak</td></tr>
<tr><td>Load Reduction Day
(when called*)</td><td colspan="7">Off Peak</td><td colspan="4">On Peak</td><td colspan="7">Off Peak</td><td colspan="4">Critical Peak</td><td colspan="2">Off Peak</td></tr>
<tr><td>Sundays and
Holidays**</td><td colspan="24">Off Peak</td></tr>
</table>

2. Benefits

By shaving even a small percentage off demand during critical hours, utilities can markedly lower electricity costs, particularly in organized markets, and avoid building new infrastructure. In some places, utilities can also bid CPP "capacity" into wholesale markets and use the revenues to offset the cost of service.

CPP and PTR programs also enable utilities to preserve reliability during emergencies. They impose relatively low costs on non-participants because of the relatively small discounts or rebates.

CPP or peak time rebate programs enable utilities lacking fuel cost adjustment mechanisms or decoupling mechanisms to reduce their exposure and thus risk from the highest wholesale electricity costs.[23] They do so by initiating CPP events and correlating rates with peak energy prices. The resulting lower risk reduces utilities' need to (a) internalize risk, (b) acquire physical hedges like generators or long term power purchase agreements, or (c) purchase financial hedges.

3. Costs and concerns

CPP and PTR programs require AMI infrastructure. These programs can require high customer sophistication, since they must quickly respond to CPP notifications. They also increase rate complexity and require customers to adjust their consumption on short notice. Programs that feature automated controls to cycle appliances can avoid added complexity and the need for customers to follow rates but feature higher up-front costs.

4. Programmatic decisions

Although regulators do not need to craft rates for PTR programs (though they have to determine rebate levels), other CPP programmatic decisions, such as who the program applies to, the number of events, the length of customer advanced notice, and the size or discounts/rebates apply to both program types.

How many times per year/hours per event should programs feature? CPP Programs vary in number and length of events. With extreme day pricing (EDP), for example, the peak rate is effective for 24 hours. Pacific Gas and Electric's CPP program events each last for six hours, the first three of which feature a moderate CPP rate of three times the normal peak TOU rate and the latter three of which feature a CPP rate that is five times the normal peak rate.[24] Southern California Edison's CPP program includes 9 to 15 four-hour events.[25] Gulf Power can call CPP events up to one percent of the time and they last for two hours.[26]

Higher numbers of CPP or peak time rebate hours and events increase potential cost savings for the utility but also increase the burden on participants, requiring additional compensation or reducing the pool of willing participants. Regulators should assess the costs and benefits of various benefit/participation level scenarios observed in existing CPP and PTR programs.

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[23] Many utilities enjoy regulatory mechanisms that allow them to pass fuel or energy costs to their consumers. These mechanisms usually contain true-up provisions that match rates to these costs, although often with a lag.

[24] http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/cpp/index.shtml

[25] http://www.sce.com/NR/rdonlyres/672CFB73-002B-4CA5-8E86-B8F481E41A48/0/0909_CPPFactSheet.pdf

[26] http://www.gulfpower.com/energyselect/the_rate.asp

How much should rates increase during CPP events? CPP programs feature rates that are three to ten times higher than flat rates. CPP rates could approximate the highest spot market prices, which can exceed average electricity prices by ten fold. Alternatively, they could consider the long-run marginal cost or the cost of capacity. The California PUC found that "the critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period."[27] Pacific Gas and Electric Company increases prices by approximately five fold during CPP events. Gulf Power features CPP rates $0.285, roughly three times higher than flat rates.

How large should discounts be for program participants? Discounts vary by utility. For instance, Gulf Power's CPP rates, which couples with TOU rates, are 1.785 and 3.021 cents per kWh during low and medium hours, compared to 3.93 cents per kWh for base rates. Regulators should calibrate CPP rates to maximize the net of electricity savings minus the costs of discounts by reviewing the results of pilot programs.

How much advance notice should the CPP program provide? Shorter lead times best enable utilities to respond to sudden changes in economic or reliability conditions. The less advance notice customers receive, however, the more onerous program participation becomes. Further, certain customers might not be able to reduce their consumption on short notice. Gulf Power provides a half hour of advance notice.[28] In contrast, Portland General Electric and Southern California Edison contact customers the day before the CPP event.[29]

Should discounts come from the fixed, demand, or energy component of rates? Discounts from the fixed component of rates provide predictable benefits for consumers and costs for the utilities. Further, they do not dampen incentives for participants to conserve electricity during non-CPP periods. I am unaware of any CPP programs featuring discounts to the fixed portion of rates or rebates. Southern California Edison's CPP program provides reduced monthly on-peak demand charges during the summer.[30] The CPUC found that peak demand rates were redundant for customers with CPP rates, effectively double charging them for peak demand.[31] In contrast,

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[27] CPUC Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, July 31, 2008, page 61. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85984.htm

[28] http://www.gulfpower.com/pricing/pdf/rsvp.pdf

[29]

http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_012.pdf

[30] http://www.sce.com/b-rs/large-business/cpp/

[31] http://www.gulfpower.com/pricing/pdf/rsvp.pdf

Gulf Power reduces the energy components of rates during most hours, advertising lower rates 87% of the time.[32]

Should CPP programs protect participants from higher bills? Depending on the size of CPP discounts and rate increases, if CPP program participants do not reduce usage during CPP events, their bills could increase, absent protective mechanisms. Pacific Gas and Electric Company provides participants with an option ensuring that for the first 12 months, their monthly electric bills are limited to 100% of what they would have been under conventional rates. Such provisions could increase participation. They could, however, diminish participants' electricity consumption reduction removing economic penalties for consumption during CPP events. Bill protection mechanisms could also apply to voluntary TOU or RTP rates.

F. Real-time pricing

1. Description

Real-time pricing (RTP) rates adjust based on fluctuations in wholesale electricity costs. Such rates capture seasonality, time-of-day, weather, maintenance, and other factors that contribute to cost fluctuations. They fully match wholesale costs with retail rates, providing customers with accurate price signals. Unlike other EIRs, RTP rates are unpredictable. Consequently, most RTP programs target large customers who can best manage risks and consumption.

Gulf Power offers the following RTP rate schedule based on the system lambda, which is the marginal, variable production cost of electricity at a given level of system output[34]:

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[32] http://www.gulfpower.com/energyselect/index.asp

[34] http://www.gulfpower.com/pricing/pdf/rtp.pdf

Customer Charge:	$1,000.00
Fuel Charge:	Fuel charges are normally adjusted by the Florida Public Service Commission annually in January. As of June 7, 2002, the amount for fuel was 2.097¢/KWH. For current fuel costs included in this tariff, see page 6.34.
Energy Charge:	The RTP hourly energy prices are derived using the day ahead projection of Southern System Lambdas adjusted to recognize embedded costs. This price is determined as follows:

$$P = \lambda \times M + D$$

Where,

"P" = hourly price in ¢/KWH

"λ" = Southern Company territorial system Lambda, projected a day ahead for each hour of the day

"M" = multiplier which is used to adjust λ to recognize embedded costs

"D" = constant amount of 0.25¢/KWH added to each hourly price

2. Benefits

RTP rates fluctuate more than TOU or seasonal rates do, increasing customers' incentive to shift or reduce consumption during peak periods. Load shifting reduces average energy costs, particularly in organized markets, and forestalls infrastructure investments. Consumption reductions help states and utilities meet energy efficiency and carbon reduction goals or mandates.

Real-time pricing programs enable utilities lacking fuel cost adjustment mechanisms to pass to customers the risk of wholesale electricity cost volatility. Such lower risk, reduces their need to either (a) internalize cost risk, (b) acquire physical hedges like generators or long term power purchase agreement, or (c) purchases financial hedges. Utilities could pass some of these benefits to customers, as discussed in Section II.D.

3. Costs and concerns

RTP requires AMI investments. Such investments can cost billions of dollars.[35] RTP also increases rate complexity and unpredictability. Customers must observe and respond to frequent rate changes, disadvantaging unsophisticated customers lacking the willingness or ability to monitor rates. Additionally, unless they adopt hedging instruments, RTP customers cannot predict their electricity costs, inhibiting investment decisions.

As discussed in section I.B.3, rate designs that affect consumer behavior increase utility revenue uncertainty. Conversely, reduced costs exposure risk could reduce revenue for certain utilities.

4. Programmatic decisions

What data should RTP rates use? Real-time rates are easiest to administer in organized wholesale markets like those of PJM and MISO that offer locational marginal prices which reveal the day-ahead and real-time wholesale costs of electricity in each hour. For this reason, California declined to make real-time prices the default for certain customers until full rollout of the Market Redesign and Technology Upgrade.[36, 37] Though perhaps less precise, real-time pricing programs can occur outside or organized markets. Gulf Power offers real-time pricing, calculating prices based on the system lambda. Some real-time rates are also based on a combination of time-of-use/seasonal rates and temperatures.[38] Where available, market data is preferable to system lambda calculations or other methods because it provides the most accurate price information.

RTP rates based on market data can draw from either hourly day-ahead prices or real-time prices. Day-ahead rates permit longer lead times for customers and reflect the cost of most power purchased in the market because utilities purchase most power in that in the day-ahead

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[35] By 2005-06, the average hardware cost per meter averaged \$76. Capital costs related to communications infrastructure installation ranges from \$125 to 150 per meter. http://www.ferc.gov/EventCalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf

[36] According to the California ISO, "MRTU is a comprehensive program that enhances grid reliability and fixes flaws in the ISO markets. It keeps California compatible with market designs that are working throughout North America and replaces aging technology with modern computer systems that keep pace with the dynamic needs of California's energy industry. The program launched March 31, 2009."

[37] CPUC Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, July 31, 2008, page 13. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/85984.pdf

[38] http://www.sce.com/b-rs/demand-response-programs/real-time-pricing-RTP-2.htm

markets and use the real-time market for system balancing. Because utilities purchase most of their power in the day-ahead market, leaving the real-time market for balancing unexpected load and generation fluctuations, day-ahead RTP rates capture most of the cost variations born by utilities. Real-time rates feature more variability and better reflect cost fluctuations though. Additionally, rates can be from the entire utility (or RTO footprint) or feature more granularity and be more location-specific. The latter features greater rate unpredictability and higher calculation complexity though.

Over what intervals should rates change? AMI technology enables utilities to communicate rate changes at intervals as frequent as every five minutes. Intervals should align with the sophistication of customers. For instance, real-time rates for large industrial customers could change every 15 minutes, while rates for residential customers could change on a bi-hourly basis. More frequent intervals require more robust (and costly) AMI systems.

Alabama Power and ConEd offer day-ahead real-time pricing rates, in which the utility informs customers the day before what rates will be for the next 24 hours. Rates reflect day-ahead, rather than real-time electricity prices.

What protections should RTP programs provide customers? Several utilities offer optional price protection products to mitigate the risk of RTP fluctuations. These products include price caps, contract for differences (CfD), collars, and index swaps. Regulators should weigh the customer benefits of these mechanisms against the resulting reductions in the strength of RTP signals. Examples of these protection products from include the following, the first three of which Alabama Power offers[39]:

> **Price caps** offer protection in the event that the average real-time price exceeds the cap price. In exchange for a premium, consumers can choose a price cap, time period, and the load amount to protect. Certain organized markets already feature price caps.
>
> **Contract for differences** (CfD) is an arrangement in which consumers pay a predetermined fixed rate over a certain time period. CfDs offer customers added cost certainty. By serving as hedging instruments, however, CfDs reduce incentives to reduce peak consumption.
>
> **Collars** create a caps and floors for the average real-time rates over a specified period. They reduce customer exposure to extremely high rates. They also provide revenue floors for utilities.
>
> **Index swaps** are financial arrangements linking an RTP swap price with a commodity price index. The swap price moves in conjunction with changes in the commodity price.

[39] http://www.alabamapower.com/pricing/pdf/ppp.pdf

Certain retail electric providers offer products that supplement hourly pricing with a physical hedge. One such product is "**block and index pricing**." This pricing mechanism enables customers to purchase blocks of electricity at a fixed $/kWh rate. For any usage in excess of the block level, customers pay spot market prices. This mechanism combines elements of real-time pricing and inclining block rates.[40]

[40] Steven Braithwait, Dan Hansen, and Michael O'Sheasy, "Retail Electric Pricing and Rate Design in Evolving Markets," Edison Electric Institute, http://www.eei.org/ourissues/electricitydistribution/Documents/Retail_Electricity_Pricing.pdf

II. Common Implementation Considerations and Decisions

For all EIRs, regulators must decide who they cover; whether they are mandatory; what, if any, steps to take to protect utilities from unpredictable or reduced revenues; and what kind of customer education utilities should conduct.

A. To whom should rates apply?

Regulators should focus on providing EIRs to customers who best can respond to price signals. If applied to unresponsive customer groups, EIRs merely reallocate costs. Such reallocation could be appropriate where existing rates inaccurately allocate costs. Rates that do not lead to behavioral changes, however, would not provide aggregate benefits by reducing peak or total consumption. Cost reallocation, particularly absent net customer benefits, often proves divisive.

As discussed in Section I.A, effective rate designs avoid undue complexity. Regulators should consider the effects of added complexity from EIRs on various customer groups. Seasonal rates are simple for even unsophisticated customers. In contrast, to benefit from RTP rates, customers must frequently monitor rates and change their consumption. RTP rates also make estimating bills more difficult for customers. Accordingly, some utilities, including Alabama Power, and Gulf Power offer real-time rates to only larger customers. Mandatory real-time rates should at least initially apply to only large customers who can predict their consumption, hedge, monitor electricity rates, and modifying their consumption in response to rate changes. Nonetheless, certain utilities, including Ameren, have offered real-time pricing to residential customers.[41]

CPP programs require customers to adjust their behavior on one day's notice or less. Large customers can best do so, particularly absent programmable thermostats that enable usage to automatically fall during CPP events. Accordingly, default rates for Southern California Edison customers with peak demand exceeding 200 kW include CPP.[42] Despite this advantage, some utilities, including Gulf Power, have offered CPP to residential customers, though on an optional basis. TOU and inclining block rate complexity fall between seasonal rates and RTP rates.

Based on these considerations, regulators and utilities must determine whether or not to implement EIRs on a wide-scale or targeted basis. Regulators need to examine various customer groups' demand elasticities to estimate how they would respond to EIRs and the implications for their bills, discussed in Section IV.

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41 http://www.ameren.com/Residential/ADC_RTP_Res.asp

42 http://www.sce.com/b-rs/large-business/cpp/

B. Should rates be mandatory, opt-in, or opt-out?

Mandatory rates maximize participation and include customers who must change their behavior to receive benefits or avoid added costs from new rates. Mandatory rates can prove politically difficult, however, as certain customer groups would likely see higher or less predictable electricity bills even if the aggregate costs fall. Certain rate designs, such as seasonal rates, are likely to cause less cost reallocation than other EIRs, such as RTP.

Voluntary rates maximize customer choice and avoid forcing customers to use rates that increase their bills. Voluntary rates, however, feature lower participation rates, particularly by customers who consume large amounts of power during peak times. One study estimates that "voluntary rate structures generally attract a relatively small percentage of customers (less than 20 percent) unless marketed heavily by the utility."[43] Voluntary rates can also lead to self-selection, where a disproportionate number of participating customers reduce their electricity bills without changing their behavior – at the expense of other ratepayers.

Optional rates include **opt-out** (default) or **opt-in** rates, where the existing rate design is the default. Opt-out rates feature higher participation levels than opt-in rates because many customers will not change their rates. In California, the Statewide Pricing Pilot featured an initial opt-in participation rate of 20%. At the conclusion of the program, only 10% of participants remained on the new rate. In contrast, Washington State implemented dynamic tariffs on an opt-out basis and reported that nearly 90 percent of customers participated.[44]

Some commissions or utilities have differentiated between customer classes when determining whether rates are mandatory, opt-in or opt-out. For instance, ConEd RTP rates are mandatory for customers with a peak demand of more than 15,000 kW but opt-in for other customers.[45] Additionally, the California Public Utilities Commission mandated default (opt-out) CPP/TOU rates for large commercial, industrial, and agricultural customers but not residential customers. In the same decision, the CPUC determined that certain customers' rates would switch to default CPP/TOU rates after they possessed AMI for 12 months to allow them to observe their usage patterns in different seasons. It determined that smaller customers need this extra time, where larger customers do not.

Where EIRs are optional, regulators can allow for EIRs to apply to only a portion of customers' demand to partially hedge against electricity cost variability. Accordingly, the California PUC found that "dynamic pricing rates should include a capacity reservation charge,

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[43] http://www.epa.gov/cleanenergy/documents/napee/napee_chap5.pdf

[44] Faruqui, Ahmad, and George, Stephen, "Demise of PSE's TOU program imparts lessons," *Electric Light and Power,* Jan. 2003.

[45] http://www.coned.com/energyefficiency/vol_time_pricing.asp

or similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity."[46]

C. How should regulators estimate changes in consumption and revenues after the introduction of EIRs?

Regulators should estimate the short-term and long-term demand elasticities of various customer classes. They should examine existing literature on the demand elasticity of different customer groups—how their consumption changes in response to changes in costs. See Section V of Part Two for further discussion on customer elasticity. This information will inform how much they must iteratively adjust rates to ensure recovery of all fixed costs.

D. How should regulators address utility risk changes from EIRs?

1. Reduced utility cost volatility

By aligning retail rates with wholesale electricity costs, EIRs can reduce utility exposure to wholesale electricity cost volatility. Real-time rates fully shift this risk to customers, followed by day-ahead real-time rates, CPP programs, time-of use rates, and seasonal rates. Inclining block rates do not reduce utility risk.

Many utilities have fuel or energy adjustment clauses that allow them to pass the cost of energy costs fluctuations to customers, although frequently with a lag. Some operate under decoupling mechanisms that separate sales from earnings. There is no reduction in the "hedging premium" where utilities can pass all energy costs through to customers or have decoupling mechanisms. According to the California PUC, "Because of the nature of long-term contracting and decoupling, there appears to be little cost-based justification to incorporate a hedging premium into rates at this time."[47]

Utilities lacking such mechanisms, such as those under rate freezes, must bear all risk of electricity cost fluctuations if they offer flat rates. Utilities can internalize the risk, causing earnings fluctuations that can degrade their credit ratings. Alternatively, they can invest in physical hedges, including owning generation or entering into long-term power purchase

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[46] CPUC Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, July 31, 2008, pages 21-26. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85984.htm

[47] CPUC Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, July 31, 2008, page 52. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85984.htm

agreements. Finally, utilities can use financial instruments to hedge, though such instruments increase total costs. Estimated risk premiums range from 11 to 15 percent of the value of consumer rates.[48]

If EIRs shift costs or risks to customers, regulators should consider requiring utilities to pass some of the benefit to customers. They can do so by lowering the return on equity or by allowing less hedging by the utility.

2. Increased utility revenue uncertainty

To varying degrees, EIRs affect utility risk of fixed cost under-recovery because many utilities include fixed costs in variable rates components. Customers could reduce aggregate or peak consumption more than expected, causing sales to fall short of the revenue requirement. A utility could also over-recover if customer behavior does not change as predicted, if participation rates are low, or if CPP programs reduce energy costs more than sales revenues.

Before attempting to mitigate risks, regulators should examine the degree of increased cost-recovery risk that utilities face due to EIRs. The more fixed costs that the energy component of rates includes, the more risk EIRs add. If EIRs increase utilities' risk, their credit ratings could fall, increasing the cost of capital. The following policies address the increased revenue risk associated with EIRs. This added risk is largely confined to the short term before customers have changed their behavior and utilities can estimate consumption and revenues as accurately as before the new rates.

a. Implement EIRs on a pilot basis. Pilot programs, common to EIRs requiring AMI, allow utilities and regulators to gauge the level of customer response to rates and the effect on sales and costs. When evaluating data from pilot programs, regulators should examine whether participation was randomized. If "energy geeks" or those with low peak demand disproportionately participate in pilots, the data is not representative of the entire customer population. Pilots would not help estimate participation rates of optional rates.

b. Implement a decoupling adjustment, which on an aggregate or per-customer level disconnects non-fuel cost recovery from consumption. Decoupling mechanisms eliminate revenue risk for utilities, although they can also eliminate potential revenue growth between rate cases due to growth the number of customers and their demand.[49] With decoupling, rates do not need to precisely estimate demand attrition resulting from EIRs.

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[48] Ahmad Faruqui and Lisa Wood, "Quantifying the Benefits of Dynamic Pricing in the Mass Market," Edison Energy Institute, January 2008.

[49] For more information on decoupling, please see "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements" by David Boonin, http://nrri.org/pubs/electricity/rate_des_energy_eff_SFV_REEF_july08-08.pdf

E. How should utilities educate customers about EIRs?

Whether EIRs are mandatory, opt-in, or opt-out, customer education is critical to their effectiveness. Customer sophistication tends to be lower for smaller customers. Many small customers do not examine their electricity bills or rate tariffs sufficiently to understand their rates. Thus, more outreach is needed for residential customers than for large industrials. Customers should (a) know about changes to their rates or new rate options and (b) understand how to minimize their bills under new rates. We recommend additional research on optimal ways to educate customers about new rates.

III. Efficiency-Inducing Rate Overlap

Each of the five discussed EIRs can operate in isolation. With the exception of RTP rates, which can operate with only inclining block rates, each of these rate designs can also work in conjunction with the others. In some cases, combining EIRs magnifies their effectiveness and redistributional consequences.

A. Combining real-time pricing and critical peak pricing, time-of-use, or seasonal rates

RTP is a substitute for CPP, TOU, and seasonal rates, capturing all of the electricity cost variations that they reflect. Thus, it cannot combine with these rates.

B. Combining critical peak pricing, time-of-use, and seasonal rates

CPP, TOU, and seasonal rates each capture part of the variations in of wholesale electric cost. Regulators can and have combined these three or combinations of two therein. Combined EIRs increase the degree of rate complexity, making them more problematic for less sophisticated customers. The example below from Dominion Power provides Virginia residential customers with rates combining TOU, seasonal, and CPP elements.[50]

[50] http://www.dom.com/dominion-virginia-power/customer-service/energy-conservation/pdf/pricing_schedule.pdf

B. Electricity Supply Service Charges

1. Electricity Supply kWh Charge

a. For the calendar months of January, February, March, and December:

kWh consumed:		
6 a.m. to 11 a.m. and 5 p.m. to 10 p.m.	@	3.957¢ per kWh
All other hours	@	1.840¢ per kWh

b. For the calendar months of April, May, October, and November:

kWh consumed:		
6 a.m. to 10 p.m.	@	2.857¢ per kWh
All other hours	@	0.011¢ per kWh

c. For the calendar months of June through September:

kWh consumed:		
10 a.m. to 10 p.m.	@	5.389¢ per kWh
All other hours	@	0.823¢ per kWh

2. Plus Electricity Supply Critical Peak kWh Surcharge (in addition to above rates)

All Critical Peak kWh	@	45.0¢ per kWh

C. Combining inclining block rates and all other EIRs

Inclining block rates do not attempt to align rates with wholesale electricity costs. Rather, they encourage customers to limit their overall consumption. As such, they are not redundant with any of the other EIRs. Combining inclining block rates with other rates increases rate complexity though. Inclining block rates can combine with other EIRs through separate energy charges, which vary with the block. Hypothetically, instead of TOU rates featuring rates of 8, 12, and 16 cents per kWh depending on the time period, they could be 4, 8, and 12 cents with a second energy change that is 0, 3, or 9 cents per kWh depending on the block. Below are proposed rates from the Hawaiian Electric Company that combine TOU and inclining block rate elements.[51]

[51] See Exhibit HECO-106 of HECO's rate filing in Docket No. 2008-0083 (2008).

RATES:

CUSTOMER CHARGE - $ per customer per month:	
Single-Phase Service - per month	$10.50/month
Three-Phase Service - per month	$18.50/month
ENERGY CHARGES - ¢ per kWh:	
TIME-OF-USE CHARGES - ¢ per kWh:	
On-Peak Period – per kWhr	43.2113 ¢/kWhr
Off-Peak Period - per kWhr	22.2113 ¢/kWhr
USAGE CHARGES - ¢ per kWh:	
All kWhr between 350 – 1,200 kWh per month–	1.0 ¢/kWhr
All kWhr over 1,200 kWh per month-	2.0 ¢/kWhr
MINIMUM CHARGE:	
Single-Phase Service - per month	$18.50/month
Three-Phase Service - per month	$23.50/month

Combining inclining block rates with other EIRs magnifies customer bill reductions or increases, depending on their load profiles. As noted in Section I, inclining block rates could increase bills for large, poor households who feature high electricity usage but cannot improve their energy efficiency. Hypothetically, such a household could be low-income (and thus unable to improve efficiency); occupy a large, older house; and include persons who are home during the daytime, necessitating peak-period HVAC usage. If inclining block rates combine with TOU rates, this customer would see bill increases associated with inclining block rates magnified because it cannot respond to peak TOU rates.

D. Combining critical peak pricing and demand response programs

Certain utilities or RTOs offer demand response programs through which utilities can require certain customers to curtail their load in emergency situations in exchange for rate discounts or direct compensation for each event. Although some customers might participate in CPP programs and not conventional demand response programs because they want to maintain control of their consumption, the two types of programs target similar customers. Some utilities or RTOs offer economic demand response programs where participants receive a credit for reducing load but their rates do not change during critical periods. These programs' critical events are likely to be the same as CPP events. Participation in CPP programs is thus likely to be low in the presence of other demand response programs.

IV. Secondary Effects of Efficiency-Inducing Rates

A. Redistributive consequences

Rate design changes often prove contentious because they reallocate costs, with each customer class seeking to bear as little cost as possible. Table 2 below describes which customers would likely benefit or suffer under various EIRs.

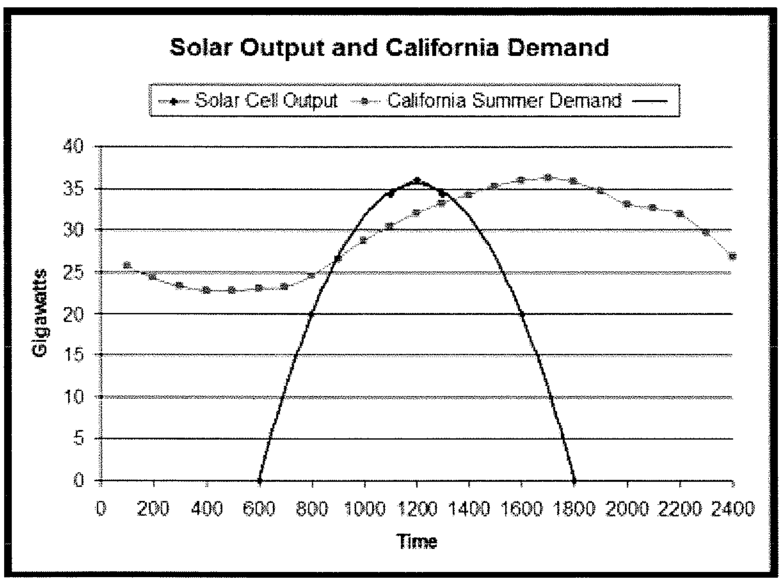
Table 2. EIR Redistributive Consequences

Rate design	**Customers likely to see reduced bills**	**Customers likely to see additional bills**
Inclining block rates	- Customers who consume low amounts of electricity, such as small households and customers with gas heating and hot water - Customers able to invest in energy efficiency (EE) measures or gas appliances	- Customers who consume large amounts of electricity such as large families - Customers who are unable to reduce consumption or invest in EE measures or gas appliances (*e.g.*, as poor customers using space heaters)
Seasonal rates	- Customers whose consumption is not concentrated in the peak season - Customers who can shift some of their consumption to the off-peak season - Customers able to invest in EE measures specific to the peak season	- Customers whose consumption is heavily in the peak season (*e.g.*, ski resorts) who cannot shift consumption to the off-peak season - Customers unable to invest in EE measures specific to the peak season (*e.g.*, poor customers)
Time-of-use rates	- Customers who have low daytime loads (*e.g.,* daytime workers) - Customers capable of shifting load from peak to off-peak times (*e.g.*, manufacturers or mining customers) - Customers capable of implementing EE measures specific to peak hours (*e.g.*, efficient air conditioners)	- Customers with high daytime usage (*e.g.*, office buildings) - Customers with low ability to shift load from peak to off-peak times (*e.g.*, retail stores) or reduce peak consumption
Critical peak pricing	- Sophisticated customers capable of observing rate changes and adjusting their consumption	
Real-time pricing	- Sophisticated customers able to monitor electricity rates and respond to changes	- Unsophisticated customers unable to monitor rates and respond to changes - Customers with fixed electricity usage or high usage during peak periods

B. Renewable energy implications of EIRs

Numerous states have or are considering implementing policies to encourage distributed renewable energy systems. Most distributed generation systems are solar PV, small wind, or anaerobic digestion generators. They offset their owners' electricity consumption. Additionally, in most states, customers with distributed generators can sell excess electricity back to the grid through net metering programs. Some states also provide tax credits, utility rebates, low-interest loans, and other incentives for distributed renewable energy generators. Many states have created markets for tradable renewable energy credits in conjunction with renewable portfolio standards. Some offer tax credits (sales, property, or income) or rebates to encourage development. Policymakers should evaluate carious EIRs' effect on the value of renewable energy generation to calibrate such incentives, such that they are sufficient but not excessive.

Most parts of the U.S. feature peak electricity consumption and wholesale electricity costs during summer, weekday afternoon hours. TOU rates, seasonal rates, and real-time pricing (and, to a lesser extent, critical peak pricing) all add value to behind-the-meter renewable energy generators that produce a disproportionate amount of their electricity these hours. Solar generators in particular match this load profile as shown below for a single summer day.[52] Biomass generators such as anaerobic digesters are dispatchable, such that they can provide their electricity when it is most valuable.



In contrast, wind turbines in most locations produce the most electricity during winter or shoulder months and in the morning or and at night, when electricity is least valuable under EIRs. States promoting small wind development (currently a small percentage of overall wind

52 http://i-r-squared.blogspot.com/2007/07/california-solar-dilemma.html

generation) should consider the effects of seasonal, TOU, and RTP rates by examining typical production profiles of wind turbines and calculating their value under different rate designs.

At the margins, CPP programs could make dispatchable, behind-the-meter generation like anaerobic digestion generators more valuable by enabling customers to switch from taking electricity from the grid to using their own generation during CPP events. CPP events are infrequent enough, and the corresponding discounts small enough, however, that CPP rates' do not markedly affect project economics.

Inclining block rates can increase or decrease the value of distributed generation, depending on the customer's electricity consumption levels and the block cutoffs. If inclining block rates reduce rates at unchanged consumption levels for the customer demographics most likely to purchase solar PV or small wind generators, these customers will be less likely to purchase them. Conversely, if these customers' rates, absent changes in electricity consumption, increase under inclining block rates, distributed generation becomes more attractive. States intending to promote distributed generation should examine what customer demographics purchases most distributed renewable energy generators and how their incentives would change under potential inclining block rates.

Part Two

Time-of-Use Rate Implementation

Introduction

Policymakers face a number of important decisions when designing dynamic rates or evaluating proposed dynamic pricing schedules. These decisions are listed in Part One, sections I and II. The purpose of this document is to provide policymakers with **practical guidelines** for implementing those decisions. In this document we focus on the process of designing time-of-use (TOU) rates. Two other types of dynamic pricing—seasonal rates and critical peak pricing—are designed in a process that is similar (with necessary variations) to the process discussed below. The designs of inclining block rates and real-time-pricing differ more significantly from this process.

Time-of-Use Pricing Design: Seven Steps

Step 1. Obtain data
Step 2. Select seasons[1]
Step 3. Select time-of-day periods[2]
Step 4. Set rates
Step 5. Estimate effects of TOU introduction
Step 6. Conduct sensitivity analysis
Step 7. Finalize TOU pricing

[1] The steps represent the typical design process of TOU pricing; in some cases the utilities choose not to separate out different seasons, thus eliminating Step 2.

[2] Seasonal pricing can be designed using the same process minus Step 3. The design of critical peak pricing requires two additional steps: the selection of critical peak hours and their pricing.

I. Step 1 – Obtain Data

TOU rates and other dynamic pricing methods attempt to reflect the underlying costs of electricity more precisely than do traditional rate structures (i.e., rate structures based on embedded costs rather than running costs) using the same average rates for every hour of the year rather than rates that vary as costs vary. A utility's costs change every hour (in fact, even more frequently). A rate structure with 24 daily changes, however, would confuse customers. Grouping hours allows the analyst to avoid such excessive precision while still producing rates that reflect cost changes.

Careful examination of a utility's data should allow the grouping of hours into different categories to create a TOU schedule that reflects variations in demand and costs. To design reasonable grouping, the analyst can employ two types of data: (1) data on the utility's loads and (2) data on the utility's marginal costs. In principle, analyses of both types of data should provide similar results: Higher loads are typically associated with higher marginal costs, since utilities have to use generation facilities with higher operating costs to meet larger demand during peak hours. In practice, however, the relationship between load level and cost level is not always proportional.[3] It is advisable, therefore, to use both types of data in the analysis if this information is available.

The cost data is either (a) the cost of a utility's production of electricity (if the utility owns the generation necessary to serve its load), or (b) the cost of purchasing electricity in organized wholesale supply markets or under bilateral contracts (if the utility purchases the necessary electricity). In organized wholesale markets the data can be obtained from a relevant ISO or RTO. If a market is **effectively competitive**, wholesale prices should reflect the actual marginal cost—the cost of producing another kilowatt-hour[4]—including how that cost varies across different seasons and hours of the day. The applicable data is the average locational marginal price paid by the utility, on average, for each kWh for each hour of the year. The zonal LMP includes both the cost of the electricity and the congestion. In states with non-organized markets (i.e., bilateral contract markets) the analyst can obtain the data from the utility.[5] Even where the utility procures some of its energy through fixed power purchase agreements, rates should

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[3] For example, higher marginal costs in a particular period might result from an increase in fuel costs rather than an increase in demand.

[4] A wholesale electricity market exists when competing generators offer their electricity output to retailers. The mere fact that sellers compete does not mean that the market is effectively competitive, however. Remember that it is possible to exercise market power that can raise prices above real economic costs. In fact, when prices in the market vary from marginal costs, that fact is a signal that the market is not effectively competitive. For detailed background on market power and its relation to marginal cost, see Rosenberg (2007).

[5] Appendix A contains an example of a data request that can be sent to a utility.

reflect the costs paid through organized markets. LMP payments are the marginal cost, and thus the cost to the utility of additional consumption or savings from reduced consumption.

It is advisable that the data cover each hour of the year. Having data at the hourly level allows for maximum precision in grouping. Having data for a couple of recent years, moreover, will mitigate the effects of anomalies associated with any particular year.[6]

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[6] Examples of such anomalies include unusual weather conditions, blackouts, and exercise of market power at the wholesale level.

II. Step 2 – Select Seasons

Consumer behavior varies with seasons—in most places people consume more electricity during midday hours in the summer months than during those same hours in the winter months. The composition of peak and off-peak hours of the day depends on the season. Thus, before identifying time-of-day pricing periods we need to separate months with similar patterns of consumption and marginal costs into distinct seasons. Then we can separate time-of-day periods within each season. The alternatives to having different seasons are (a) to create a different TOU schedule for each month, or (b) to apply the same TOU schedule for the whole year, ignoring any seasonal differences. Comparing these alternatives, seasonal grouping offers a better balance between precision and convenience. The example below illustrates how seasons are selected for a hypothetical Utility X.[7]

Figure 1 shows the distribution of hourly marginal costs for each month for Utility X.[8] The graph indicates the presence of two different patterns: a distribution of costs with two peak periods (November through March) and a distribution with one peak period (April through October).[9] Thus, two distinct seasons can be suggested: winter and summer.[10]

The shapes of the distributions of Utility X's marginal costs are related to variations in temperature and the usage level of cooling/heating appliances. The summer period features one peak period (midday hours), which has the highest marginal costs. The midday air conditioning load leads to the dispatch of expensive peaking units, driving up the cost of electricity. The winter months feature two peaks (morning hours and evening hours) due to high demand for heating during the morning hours (when people wake up) and during the evening hours (when they come home from work).

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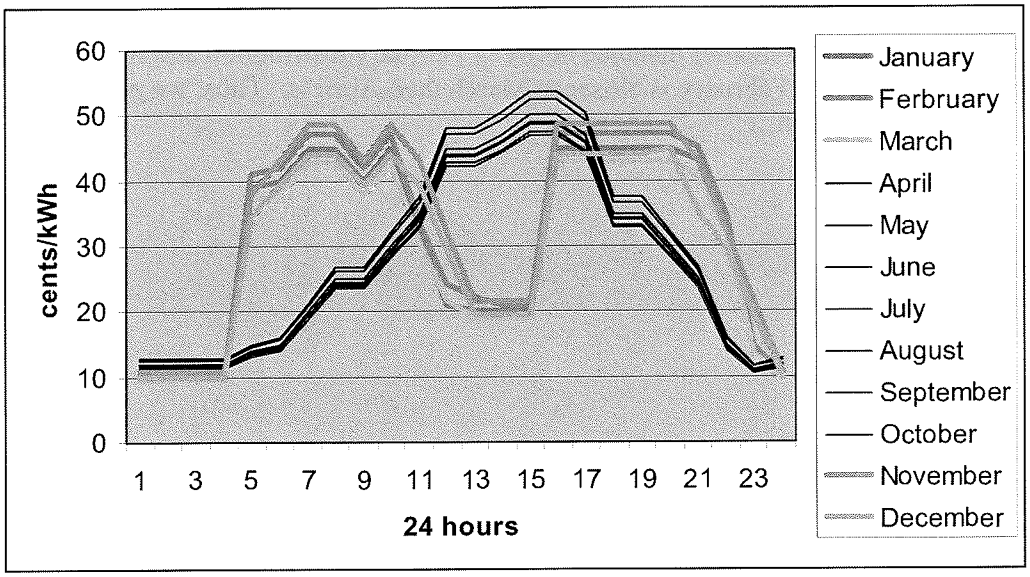
[7] The analysis uses marginal cost data. Load data can be employed in a similar fashion.

[8] Each data point is an average of the cost of a particular hour for each of the 30 days of the month. The data appear in Appendix B.

[9] The winter months of November through March are represented on the graph by thick lines of light colors, the summer months of April through October by thin lines of darker colors.

[10] This stylized example includes a substantial difference between the summer and winter months. It is possible to have more than two seasons for other utilities. For instance, some regions feature distinct fall and spring shoulder months with lower peak loads.

Figure 1. Marginal Costs of Utility X.



The analyst can examine a number of statistics in order to identify which month belongs to which season when it is not clear from the graphical representation. The analyst can calculate the coefficients of correlation and overall distances between distribution curves pairwise for adjacent months.

Let us say we have to decide where the month of March belongs: to the winter period that includes November through February or to the summer season of April through October. We can look at the coefficients of correlation[11] between March and February (the closest month of winter) and between March and April (the closest month of summer). The coefficient of correlation between March and February is 0.99[12], which is much higher and more statistically significant than the coefficient of correlation between March and April (0.33 and statistically insignificant). The coefficients indicate that the patterns of consumption in March and February are more similar to each other than the patterns of consumption in March and April.

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[11] The coefficient of correlation measures how well a trend in one variable follows the same trend in another variable. The correlation coefficient is a number between 0 and 1. If there is no relationship between the two variables, the correlation coefficient is close to 0; the stronger the relationship, the higher the correlation coefficient will be. Coefficients of correlation can be readily calculated using Microsoft Excel or any major statistical software package.

[12] The coefficients can be obtained with the help of any statistical package or MS Office Excel.

We can also calculate the sums of the squared distances between corresponding points of the distributions (the points that represent marginal costs at the same hour of the day in different months).[13] This statistic is 278.38 for February and March, and 6,110.97 for March and April. The smaller distance between February distribution and March distribution indicates that February is closer to March than April is. Thus, we place March in the winter season.

[13] The statistic shows how close the distributions are to each other. The statistic is calculated as the square of the sum of the differences in the values of marginal costs in the same hours of the day in two different months. The statistic can be calculated using Microsoft Excel or any major statistical software package.

III. Step 3 – Set Hours

After identifying seasons, the next task is to group hours of the day into distinct time-of-day periods within each season. The analyst has to select the optimal number of time-of-day periods, as well. Such periods should reflect the variations in marginal costs across the 24-hour period. The TOU schedule should not only reflect the cost of electricity supply; it also should induce a cost-reducing response from customers. The schedule therefore should (a) be accurate (in terms of the relationship between price and cost), (b) be convenient for customers, and (c) provide enough incentives for customers to adjust their behavior.

The analyst can employ a number of **statistical techniques** to group hours. An example of the application of one of these methods, cluster analysis, is provided below. We briefly introduce other methods later in the text.

A. Cluster analysis

A cluster analysis is a technique used in various disciplines to assign a set of observations (data points) to subsets (clusters), such that observations in the same cluster are similar in some characteristics (in our case, marginal costs or load levels), but have different characteristics between the clusters.[14] The example below illustrates how a cluster analysis is applied to identify periods of the day within the winter season for Utility X. In our analysis, an observation is the marginal cost at a particular hour of the day. A cluster analysis can be based on one or more variables (characteristics) per observation. For example, hourly marginal costs on an average day could constitute the basis for a one-variable cluster analysis. Alternatively, the analyst can use additional variables to reflect the variation between clusters in electricity demand and costs more accurately. In our example, cluster analysis is based on the following three variables: marginal costs on a minimum peak day[15] of each hour of the day of Utility X, costs on a maximum peak day, and costs on an average day (the average of 30 days of the month). With this three-variable cluster analysis[16], we are seeking to group hours of the day, within a season, such that within each group of hours there is a similarity of marginal

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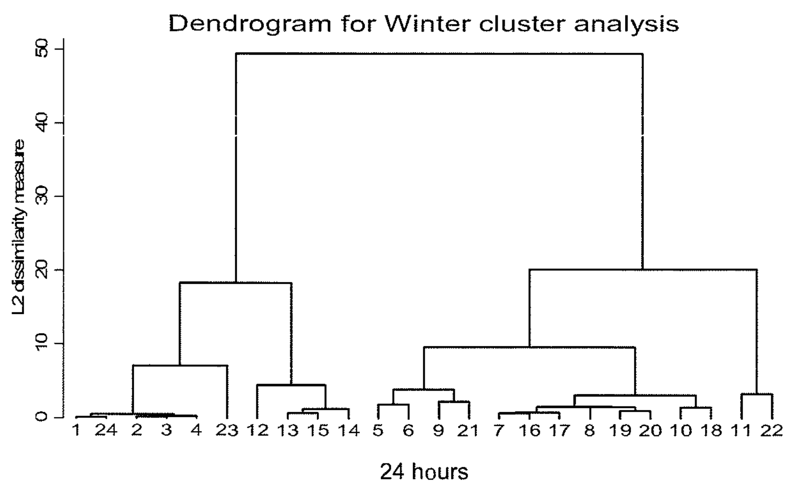
[14] Cluster analysis can be carried out with the use of a statistical package such as STATA, SAS, or SPSS. The application of this technique is relatively simple; examples of codes can be found in the STATA manual or STATA help function. For a discussion of the mathematical basis for clustering analysis, see Brian S. Everitt et al., *Cluster Analysis* (2001); Hartigan, J., *Clustering Algorithms (Probability & Mathematical Statistics)* (1975); or Charles Romesburg, *Cluster Analysis for Researchers* (2004).

[15] The marginal costs during the peak period on the minimum (maximum) peak day are at their lowest (highest) compared with other days of the month.

[16] Data for the hypothetical Utility X that is used in the cluster analysis are provided in Appendix II.

costs; and such that between each group, there is a difference in these costs. The output from the three-variable cluster analysis for Utility X is represented by the dendrogram[17] in Figure 2.

Figure 2. Cluster Analysis Output



The dendrogram indicates the possibility of two reasonable grouping solutions.[18] One solution assumes two clusters; the other, four.[19] The two-cluster solution consists of

[17] A dendrogram graphically presents how observations are grouped together at various levels of dissimilarity. At the very bottom of the dendrogram, each observation constitutes its own cluster. The observations continue to unite until, at the top of the dendrogram, all observations are grouped together. The height of the vertical lines indicates the strength of the clustering: The longer the vertical lines, the more distinct the separation between the groups. The Y axis measures the degree of dissimilarity. The X axis lists hours that are included in different clusters. A dendrogram can be obtained after performing a cluster analysis in STATA or another statistical package.

[18] Cluster-analysis stopping rules can help to determine the optimal number of clusters when it is difficult to do this based on graphical results alone. A stopping-rule value is computed for each cluster solution (e.g., at each level of the cluster tree). Larger values (or smaller, depending on the rule) signal more distinct clustering. These values help to decide when to stop clustering. In general, clustering should be stopped when the clusters are not very different from each other.

[19] Other groupings of hours are also possible, with more precise grouping of hours found closer to the bottom of the dendrogram. It is not feasible, however, to offer customers a pricing schedule that asks them to pay a different rate every hour or every couple of hours.

lower-cost hours (1, 2, 3, 4, 12, 13, 14, 15, 23, 24) and higher-cost hours (5, 6, 7, 8, 9, 10, 11, 16, 17, 18, 19, 20, 21, 22). The four-cluster solution allows us to price electricity at a more precise level; thus, the following discussion focuses on this solution.

The four-cluster solution suggested by the analysis consists of the following groups: off-peak hours (23, 24, 1, 2, 3, 4), peak hours (morning: 5, 6, 7, 8, 9, 10, and evening: 16, 17, 18, 19, 20, 21), shoulder hours (hours 12, 13, 14, 15), and two sporadic hours that are not adjacent to each other and do not belong to the other categories (11 and 22).

A careful look at the composition of hours in each category reveals an important issue in designing TOU pricing schedule: the **tradeoff between precision of grouping and adjacency of hours**. The grouping suggested above separates two nonadjacent hours, 11 and 22, from the other four clusters. Pricing these two hours separately would create an inconvenience (and higher complexity) for customers. Instead of blindly following the results of a technical analysis, the analyst should apply her subjective opinion—and her common sense—to place these hours in other categories. In our case, hours 11 and 22 can be added to the peak hours, because, according to Figure 2, at the higher level of aggregation these hours are clustered with the peak hours.

As a result of the preceding discussion, we can suggest the following TOU schedule for Utility X.

Table 1. TOU Pricing Schedule

Period	**Off-Peak**	**Shoulder**	**Peak**
Hours	11 p.m. - 4 a.m.	12 p.m. - 3 p.m.	Morning: 5 a.m. - 11a.m. Evening: 4 p.m. - 10 p.m.
- Range of marginal costs (¢/kWh)[20] - Average (¢/kWh)	10.1 - 14.2 10.8	20.2 - 33.4 21.0	39.5 - 45.7 42.4

One question that arises from the examination of the above schedule is whether there should be a distinct shoulder period. Again, the more periods we have, the less convenient and more complicated the TOU rates become for a customer to follow. At the same time, if consumers do not see enough difference in the prices they pay in different periods, they are not going to shift their consumption between periods. To address this question, one could examine the ratio of marginal costs in different periods. This ratio is useful because it reveals the distance between rates in different periods. In case of Utility X, this ratio is approximately 1:2:4 (off-peak: shoulder: peak).

[20] The data can be found in Appendix B.

While there is no rule of thumb that tells us what exactly the ratio between the periods should be in order to determine the appropriateness of creating a separate pricing period, the results of the previous studies provide some guidance. A Wisconsin TOU pricing experiment showed that residential consumers reacted by switching consumption from peak to off-peak during the summer months by about 11 to 13% in response to a peak-to-off-peak price ratio of 2:1. When the ratio was 10:1, the response was 15 to 20%.[21] Faruqui and George (2005) found that TOU rates with a peak-to-off-peak ratio of around 2 to 1 produced peak-period reductions in the 5% range during California's Statewide Pricing Pilot. In general, it seems that if the ratio between any two periods is less than 1 to 2, it does not make sense to separate these periods due to potentially insignificant customer responses.

The other question is how to price weekend and holiday hours. Most of the utilities that employ TOU pricing categorize these hours as off-peak and price them accordingly. In some cases, however, the marginal costs of electricity on weekend and holiday afternoons are much closer to weekday shoulder or peak prices. In addition, weekend and holiday loads represent a non-trivial fraction of a utility's overall load; thus it is advisable to price these hours more precisely in order to optimally align rates with costs and correspondingly modify consumer behavior. With weekend and holiday hours separated from the other off-peak hours and shoulder hours (so as to give them their own price), a pricing schedule might take the following form:

Table 2. TOU Pricing Schedule (weekend/holiday hours are priced separately)

Period	Off-Peak	Shoulder	Peak
Hours	Weekdays: 11 p.m. - 4 a.m. Weekends & holidays: 12 a.m. - 9 a.m.	Weekdays: 12 p.m. - 3 p.m. Weekends & holidays: 10 a.m. - 11 p.m.	Weekdays: Morning: 5 a.m. - 11 a.m. Evening: 4 p.m. - 10 p.m.

B. Other statistical analyses

Cluster analysis is not the only technique that allows identification of TOU periods. We briefly describe other available statistical methods next.[22] In general, all these methods serve to identify groups of hours that have similar characteristics (loads or costs) within themselves, but different characteristics between them.

> The *ANOVA method* helps to select breakpoints between different periods that make (a) the variation of costs within TOU periods as small as possible, and (b) the variation of costs between TOU periods as large as possible.

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[21] Caves, D.W., and L.R. Christensen (1983).

[22] A more detailed discussion of these methods, along with their applications, can be found in Conway (1982).

The *equal variance method* identifies breakpoints that make variances of costs in different periods the same to ensure that costs are equally homogeneous in each period.

The *minimax method* helps to determine breakpoints that make the difference between the highest and lowest costs in each TOU period as small as possible.

All of these techniques are supposed to provide guidance in designing time-of-use rates. At the end of the day, however, many decisions about rate design are left to the analyst's discretion. Blind application of the results of a technical analysis could lead to ineffective pricing schedules. Examples of ineffectiveness would include TOU schedules that fail to provide incentives to consumers (i.e., schedules that set rates at a very similar level for different periods) and schedules with an unreasonably large number of periods.

IV. Step 4 – Set Rates

Having determined the appropriate number and timing of the periods, the next step is to decide the rates for each period. Rates can be based on average marginal costs (i.e., the average of the hourly marginal costs within the period) or average weighted (by load) marginal costs in each period. There is a problem, however, with basing the rate on marginal cost: The utility will not recover its revenue requirements. Marginal cost price recovers only marginal cost—the cost of running the utility for that hour, mostly energy and some other variable costs. The utility incurs other costs, which it normally recovers through customer charges and demand charges, (i.e., charges that do not vary with hourly usage). There are also costs associated with the introduction of TOU pricing, such as the installment and maintenance of advanced meters and customer education. The difference can be covered by either scaling up[23] rates based on marginal costs or through fixed charges (as with traditional rates). In choosing the method of recovering these other costs, the analyst should take care not to disturb or blur the incentives provided to customers by dynamic pricing, (i.e., the incentive to shift load to the lower-cost periods). These incentives can be preserved by keeping the ratio between different periods' rates close to the ratio between marginal costs in these periods.

The purpose of TOU pricing is to **induce changes in consumers' behavior**. The TOU introduction will affect a utility's loads and revenues. Thus, it is important to conduct forecasts before making a decision about the launching of a new pricing scheme. The next section discusses how to estimate the effects of TOU introduction on utility's loads and revenues.

[23] "Scaling up" means proportionally increasing rates in all the periods while keeping the same ratio between the periods.

V. Step 5 – Estimate the Effects of TOU Introduction

Having developed the TOU schedule and rates, the next step is to estimate the effects of a TOU schedule's introduction on a utility's loads and revenues. This step will compare TOU rates to traditional rates to reveal whether expected revenues from TOU pricing meet revenue requirements. This information will also allow the comparison of TOU pricing to alternative dynamic rates, such as seasonal pricing, critical peak pricing, real-time pricing, and inclining block rates.

This task requires estimates of customers' **price elasticity of electricity demand**. The price elasticity of demand is a measure of the sensitivity of the quantity demanded to changes in price. While numerous studies have examined the elasticity of demand for electricity, the results of these studies are inconclusive, with wide variations in results. An accurate estimation of the TOU effects requires information on two types of elasticity: "own-price" elasticity[24] and "cross-price" elasticity.[25] In addition, customer classes likely differ in their response to a rate change. For example, commercial customers who operate businesses during the day might be less willing to reduce the timing or amount of electricity consumption than residential customers. Thus, estimates of demand elasticities for different groups of customers are required. A summary of elasticities based on a review of the existing studies is provided in Appendix C.

The example below illustrates how to apply elasticities to calculate the effect of TOU on the loads and revenues of Utility X's residential customers. Calculations for other types of customers can be carried out in a similar fashion using corresponding elasticity estimates.

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[24] *Own-price elasticity of demand* is a percentage change in quantity demanded in response to a percentage change in price of the same good or service. For example, a morning own-price elasticity of -0.25 indicates that if the price of electricity in this period goes up by 1%, the demand in this period decreases by 0.25%. A review of existing studies reveals that most estimates of elasticities are found in the range of -0.12 to -0.35. EPRI White Paper (2008) provides a review of the most recent studies of customer response to dynamic rates programs.

[25] *Cross-price elasticity of demand* is a percentage change in the demand for good A that occurs in response to a percentage change in the price of good B. Let us view electricity in the morning as a good that is distinct from electricity in midday. The question is whether the customer would substitute one for another, just as a traveler might substitute a train ride for an airplane ride. If the cross-price elasticity between morning and midday is -0.10, then if the price of electricity in the midday period goes up by 1% the demand in the morning hours decreases by 0.10%. This customer does not view morning consumption as a substitute for midday consumption; rather, she views these two goods as complements and consumes them together. Thus, if the price during one period increases, the customer will reduce consumption during both periods.

Faruqui and George (2002) provide the following matrix of own- and cross-price elasticities that the analyst can employ in order to estimate the response of residential customers.

Table 3. Elasticity Matrix for Residential Customers

2nd good / 1st good	Morning	Midday	Evening	Night
Morning	-0.25	-0. 10	-0.05	0.15
Midday	-0.10	-0.25	-0.05	0.05
Evening	-0.10	-0.05	-0.20	0.05
Night	0.15	0.05	0.15	-0.15

Source: Faruqui and George (2002), p. 55. In order to find out how demand for electricity in the morning period (1st good) is going to respond to changes in the price of electricity in the evening period (2nd good) we first locate the 1st good (morning period) in the horizontal cells, and then find a corresponding 2nd good (evening period) in the vertical cells. Following this procedure gives us the value of -0.05.

Own-price elasticities can be found in the shaded cells on the diagonal; cross-price elasticities in the off-diagonal cells. In some periods, the values of cross-price elasticities are negative; in other periods, positive. A negative sign indicates that two goods (in our case, consumption of electricity) are complements; a positive sign means that two goods are substitutes.

According to the matrix, electricity demand in the morning, midday, and evening periods are complements for each other and substitutes for the night period. For instance, the cross-price elasticity between morning and night of 0.15 shows that when the price of electricity in the night period goes up by 1%, people start substituting night-period electricity for morning-period electricity by 0.15% (for example, by changing the times at which they do laundry or cook).

Next, the analysis applies elasticity estimates to Utility X's residential loads and marginal costs to estimate the effect on the utility's loads and revenues. The following example illustrates the calculation process.

Table 4. Estimation of TOU Effects on Utility X's Loads and Revenues

TOU period	Load (mWh)	Marg cost (c/kWh)	Trad rate (c/kWh)	% change	Trad revenue ($)	Effect on load (night) %	Effect on load (morning) %	Effect on load (evening) %	Effect on load (shoulder) %	TOU load (mWh)	TOU revenue ($)
Night (off-peak)	32,384	10.8	35.0	-69.1	11,334,400	10.4	-10.4	-3.5	-3.5	37,149	4,012,100
Morning (peak)	144,716	42.4	35.0	21.1	50,650,600	3.2	-5.3	-2.1	-2.1	126,316	53,558,151
Evening (peak)	151,959	42.4	35.0	21.1	53,185,650	3.2	-1.1	-4.2	-1.1	140,106	59,405,028
Midday (shoulder)	41,903	21.0	35.0	-40.0	14,666,050	-2.0	4.0	2.0	10.0	43,316	9,096,303
Total	370,962				129,836,700	14.7	-12.7	-7.8	3.4	346,887	126,071,582

In this example, the traditional flat rate charged by Utility X is 35 cents/kWh. New TOU rates are set at the average marginal costs (from Table 1). The values of elasticities from Table 3 are applied.

The following explains how to estimate the effect of the TOU pricing on the load in the shoulder period.

- First, we calculate the **conservation effect**. The price in the shoulder period decreases from 35 cents to 21 cents, or by 40%. This percentage change is then multiplied by the shoulder own-price elasticity of -0.25, which gives an increase in the shoulder load of about 10%.

- In addition, we have to take into account another effect—the **effect of load shifting** between periods of the day.

  - The night price decreases from 35 cents to 10.8 cents, about 69%. Night and midday shoulder periods are substitutes with a cross elasticity of 0.05; thus the shoulder load decreases by 3.5% in response to the decrease in the night price.

  - The evening price increases by 21.1%, and the evening and shoulder are complements with a cross elasticity of -0.05; thus the effect on shoulder load is a decrease of 1.1%.

  - The morning price decreases by 21.1%, and the shoulder and morning are complements with a cross elasticity of 0.10; thus the shoulder load decreases by 2.1%.

- Overall, when we sum the results of both effects, the shoulder usage increases by about 3.4% due to the changes in prices of all four time periods and the complementarity/substitutability pattern between periods.[26] This 3.4% is then multiplied by the shoulder load under the traditional rate structure to obtain the load under TOU.

The identical process is applied to the other three periods of the day. Overall, the results from the table show that TOU introduction is associated with a decrease in load by about 6.5% (from 371,000 mWh under the traditional rate structure to 347,000 mWh under TOU). Revenues in response to TOU introduction decrease from $130 million to $126 million, or by about 3%. In Step 7 we discuss how to cover the gap in revenues under a TOU regime and under a traditional rate regime.

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[26] Alternatively, the calculation can be presented in the following way:
% Δ shoulder usage = Conservation Effect + Shifting Effect = (% Δ price shoulder period * own-elasticity in shoulder period) + (% Δ price night period * cross-elasticity of shoulder and night + Δ price evening period * cross-elasticity of shoulder and evening + Δ price morning period * cross-elasticity of shoulder and morning).

In this paper we estimate only the effect that TOU rates have on consumer demand, and utility's loads and revenues. However, the introduction of dynamic rates has other effects as well. For example, the Pricing Impact Simulation Model (PRISM) Suite developed by the Brattle Group not only simulates customer response to dynamic pricing, but also estimates customers and utilities' benefits. The models help to assess the following benefits: capacity cost savings, energy cost savings (lower energy generation costs and avoided wholesale power purchases), transmission cost savings, and distribution cost savings.

The PRISM models are based on the data from 2003-2005 California Statewide Pricing Pilot. However, the models can help to evaluate the effects of dynamic rates programs of utilities in other parts of the country as well. The models allow adjusting for different climates, load shapes, and socio-demographic conditions. [27]

[27] For more details see Faruqui, A, and Wood, L. (2008).

VI. Step 6 – Conduct Sensitivity Analysis

The review of existing elasticity studies reveals that it is virtually impossible to pinpoint demand elasticity. Since the results of our calculations depend on the **assumptions about demand elasticity**, it is important to perform a sensitivity analysis. Sensitivity analysis is a procedure that determines how sensitive the analysis's outcomes are to changes in assumptions. If a small change in assumptions results in relatively large changes in the outcomes, the outcomes are said to be sensitive to that assumption.

The literature allows us to identify the range of reasonable elasticity estimates: from -0.12 to -0.35.[28] Higher values of elasticity reflect a larger customer response. An application of the lower and upper bounds of the range provides us with the range of loads and revenues we can expect from the introduction of TOU pricing.

The elasticity matrix from Table 3 is adjusted for the lower and upper ends of elasticity estimates. The values of elasticities in Table 5 represent a lower end of the elasticity range, thus reflecting a smaller consumer response. The higher values of elasticities in Table 6 reflect the upper end of the elasticity range and a larger customer response.

Table 5. Elasticity Matrix for Sensitivity Analysis (lower bound - 0.12).

2nd good / 1st good	Morning	Midday	Evening	Economy
Morning	-0.12	-0.048	-0.024	0.072
Midday	-0.048	-0.12	-0.024	0.024
Evening	-0.048	-0.024	-0.096	0.024
Night	0.072	0.024	0.072	-0.072

Table 6. Elasticity Matrix for Sensitivity Analysis (upper bound - 0.35).

2nd good / 1st good	Morning	Midday	Evening	Economy
Morning	-0.35	-0.14	-0.07	0.21
Midday	-0.14	-0.35	-0.07	0.07
Evening	-0.14	-0.07	-0.28	0.07
Economy (off peak)	0.21	0.07	0.21	-0.21

Next, we perform the procedure described in Step 5, applying different values of elasticities from the above tables. Table 7 presents the results of the sensitivity analysis that reflect changes in loads and revenues under new assumptions.

[28] The values of demand elasticity for customers of actual utilities are expected to lie in this range.

Table 7. Results of Sensitivity Analysis

	Elasticities from Table 3	Lower-Bound Elasticities from Table 4	Upper-Bound Elasticities from Table 5
Change in revenue:	-6.5%	-3%	-9%
Change in load:	-3%	2%	-7%

The sensitivity analysis indicates that assumptions about the values of elasticities do not critically affect results. As we can see, even under upper-bound elasticities that assume large response from customers, changes in both revenues and loads due to the introduction of TOU pricing regime do not exceed 10%. Under lower-end estimates, revenues decrease by 3% and loads increase by 2%; under upper-end values, revenues drop by 9% and loads decrease by 7%. This is not a surprise, given that demand for electricity is not very elastic (consumers do not change their behavior much in response to changes in prices), as indicated by the small values of demand elasticity. If consumers do not adjust their patterns of consumption significantly, we cannot expect dramatic changes in sales.

In this report we apply the values of elasticities for the **short run**. Most of the TOU experiments and programs were in place for only a short period of time; thus there is not much evidence regarding the long-term effects of TOU schedules. Two studies that examined the long-run effects of the Duke Power TOU program, which was in place for eight years, came to opposing conclusions regarding residential and non-residential customers. Taylor and Schwarz (1990) studied the long-run response of residential customers. The study concludes that "customer response increases over time in a manner that enhances the ability of TOU rates to reduce system peak."[29] Tishler (1989) comes to the opposite conclusion for non-residential customers: "Almost all the firm's adjustments take place at the time that the time-of-use pricing is introduced, and only very few additional adjustments take place in the long run."[30]

Neither of the studies provides estimates of own and cross elasticities applicable for our analysis. King and Chatterjee (2003) provide a range of long-run estimates for residential customers from 34 non-TOU studies conducted before 1984. The values vary from -0.6 at the lower end of the range to -1.2 at the upper end. These values can be applied if the regulator is interested in estimating the long-run effects of a TOU program. However, these elasticity values merit careful consideration. First of all, they come from non-TOU studies, and non-TOU studies in general show higher elasticities than TOU studies. Second, the estimates come from studies conducted before 1984; more recent studies indicate lower elasticities, either due to changes in consumers' behavior over time or due to improved estimation techniques.

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[29] Taylor & Schwarz (1990), p. 431.
[30] Tishler (1989), p. 69.

VII. Step 7 – Finalize TOU Pricing

Equipped with the information from Steps 5 and 6, policymakers can make a decision about the feasibility of, and possible benefits from, TOU introduction. The decision should take into account (a) whether TOU pricing will induce enough response from customers to meet the utility's goal of peak-load reduction, and (b) how large the gap will be between TOU revenues and the utility's revenue requirements. If the decision is to proceed with TOU implementation, then the policymakers can use information from the previous two steps to adjust TOU rates upwards to cover the utility's costs and meet revenue requirements. Rates should increase to compensate for potential under-recovery of *fixed* costs (and thus earnings) due to changed consumption. Where consumption changes reduce costs as much as revenues, no adjustment is needed.

As suggested in Step 4, the adjustment can be done by either proportionally increasing rates based on marginal costs or adding fixed charges. Rates should only be increased to reach the revenue requirement. Reductions in consumption could reduce the revenue requirement by lessening fuel or maintenance costs. If a 10% reduction in consumption would cause a 10% decrease in costs (fuel and maintenance), such an upward adjustment is not necessary.

In our example, the costs did not fall as a result of reduced consumption. The marginal-cost-based rates for Utility X from Table 1 are 10.8 cents for off-peak hours, 21.0 cents for shoulder hours, and 42.4 cents for peak hours. In order to minimize the gap between revenues under traditional flat rates and TOU rates, rates in all TOU periods can be multiplied, for example by 1.0505 times. This method covers the gap while keeping the ratio intact (it is still about 1:2:4).[31]

[31] The difference is now $142.00 instead of -$376,512.00.

VIII. Conclusions

This supplemental piece provides step-by-step guidance for the designing of TOU pricing. A simplified example of a hypothetical Utility X helps to illustrate the main steps of the process.

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Appendix A

Data Request

Please provide:

1) The average 24-hour load profile for each month in the last five calendar years for each type of the utility's customers

2) The average 24-hour marginal electricity costs in the last five calendar years based on:

   - the heat rates/fuel costs of the last units dispatched if a utility produces electricity itself; or

   - the cost of electricity purchased under bilateral contracts[32]

3) Currently effective rate schedules

[32] This is a data request for utilities that operate in states without organized markets. For utilities that operate in organized markets, the data on marginal costs are locational marginal prices (LMP) that can be obtained from the appropriate RTO's website. If the data are not readily available from the website, the data request should be sent to the RTO.

Appendix B

Data for Utility X

Hour	Marg cost on average day (c/kWh)	Marg cost on min peak day (c/kWh)	Marg cost on max peak day (c/kWh)	Average load (mWh)
1	10.12	9.2092	11.638	5,060
2	10.12	9.614	11.9416	5,060
3	10.12	9.5128	11.8404	5,060
4	10.12	9.8164	11.9416	5,060
5	39.468	36.31056	44.99352	19,734
6	40.48	37.6464	45.7424	20,240
7	45.54	45.0846	52.371	22,770
8	45.54	43.7184	51.0048	22,770
9	40.48	39.6704	47.3616	20,240
10	45.54	42.8076	54.1926	22,770
11	32.384	31.41248	35.94624	16,192
12	22.876	21.27468	26.53616	11,438
13	20.45	19.8365	23.722	10,225
14	20.24	18.4184	23.6808	10,120
15	20.24	19.4304	23.276	10,120
16	45.54	44.6292	51.9156	22,770
17	45.54	45.0846	51.4602	22,770
18	45.54	41.4414	53.7372	22,770
19	45.54	43.263	52.8264	22,770
20	45.702	43.87392	52.10028	22,851
21	42.656	39.24352	47.77472	21,328
22	33.396	31.05828	39.07332	16,698
23	14.168	13.17624	16.15152	7,084
24	10.12	9.3104	11.638	5,060

Period	Off-Peak	Shoulder	Peak
Hours	11 pm - 4 am	12 pm - 3 pm	morning: 5 am - 11am evening: 4 pm - 10 pm

Appendix C

Summary of the Review of Elasticity Studies

Elasticities of Residential Customers

There are a number of studies of the demand elasticities of residential customers. Estimates found in these studies vary widely, from -0.076 to -2.01 for the short run and from -0.07 to -2.5 for the long run. The findings of most studies are located in the range of -0.12 to -0.35.

Studies of time-of-use programs and experiments show that own-price elasticity in peak periods is usually higher than elasticity in off-peak periods. Voluntary TOU programs and experiments show a higher response than mandatory programs.

In the long run, customers can change their appliance stock or install insulation; thus elasticities are expected to be higher than in the short run. Estimates for the long run, however, are less reliable, since most of the TOU projects were short-lived.

Elasticities of Non-residential Customers

There is much less information about elasticities for non-residential customers than for residential customers.

There is some evidence (from real-time pricing studies) that larger customers, especially in manufacturing, tend to be more price responsive, perhaps due to the fact that some of them own on-site generators. Hopper et al. (2006) examined the response of businesses in different sectors to the introduction of day-ahead pricing program and found that "the manufacturing sector exhibited the highest elasticity, of 0.16….The other sectors—commercial/retail, health care, and public works—are considerably less responsive, with average elasticities of 0.06, 0.04 and 0.02, respectively."[33] The results of the Braithwait and O'Sheasy (2002) study on real-time pricing indicated that "the most responsive customer segment was a group of very large industrial customers. This group exhibited a price elasticity of –0.18 to –0.28 across the range of reported prices ($0.15/kWh to $1.00/kWh), which was double the elasticity of any other group. The least responsive customer segments, consisting of smaller C&I customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of - 0.06 or lower at all price levels."[34]

The EPRI White Paper (2008) provides a review of the most recent studies of residential and non-residential customers' response to dynamic rates programs.

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[33] Hopper et al. (2006), p. 10.
[34] U.S. Department of Energy (2006), p. 88.