



A REVIEW OF ALTERNATIVE RATE DESIGNS

INDUSTRY EXPERIENCE WITH TIME-BASED AND DEMAND
CHARGE RATES FOR MASS-MARKET CUSTOMERS

1820 FOLSOM STREET | BOULDER, CO 80302 | RMI.ORG
COPYRIGHT ROCKY MOUNTAIN INSTITUTE

PUBLISHED MAY 2016
DOWNLOAD AT: WWW.RMI.ORG/ALTERNATIVE_RATE_DESIGNS

AUTHORS & ACKNOWLEDGMENTS

AUTHORS

Aman Chitkara, Dan Cross-Call, Becky Li, and James Sherwood

* Authors listed alphabetically. All authors are from Rocky Mountain Institute unless otherwise noted.

Editorial Director: Cindie Baker
Editor: David Labrador
Art Director: Romy Purshouse

CONTACTS

For more information, please contact:
James Sherwood (jsherwood@rmi.org)
Dan Cross-Call (dcrosscall@rmi.org)

SUGGESTED CITATION:

James Sherwood et al., *A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass-market customers* (Rocky Mountain Institute, May 2016), http://www.rmi.org/alternative_rate_designs.

ACKNOWLEDGMENTS

The authors thank the following individuals and organizations for offering their insights and perspectives on this work:

Severin Borenstein, University of California, Berkeley
Peter Cappers, Lawrence Berkeley National Laboratory
Na'im Darghouth, Lawrence Berkeley National Laboratory
Lena Hansen, Rocky Mountain Institute
Ryan Hledik, The Brattle Group
Virginia Lacy, Rocky Mountain Institute
Jim Lazar, Regulatory Assistance Project
Matt Lehrman, City of Boulder, Colorado
Chris Nelder, Rocky Mountain Institute
Rich Sedano, Regulatory Assistance Project

Research for this report was partially funded by a contract from the New York State Energy Research and Development Authority (NYSERDA). NYSERDA has not reviewed the information contained herein, and the opinions expressed in this report do not necessarily reflect those of NYSERDA or the State of New York.



ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. In 2014, RMI merged with Carbon War Room (CWR), whose business-led market interventions advance a low-carbon economy. The combined organization has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

TABLE OF CONTENTS

<i>Executive Summary</i>	5
<i>01: Context</i>	10
<i>02: Research Insights: Time-Based Rates</i>	17
<i>i. Types</i>	17
<i>ii. Design Dimensions & Impacts</i>	21
<i>iii. Key Takeaways</i>	44
<i>03: Research Insights: Demand Charge Rates</i>	48
<i>i. Types</i>	48
<i>ii. Design Dimensions & Impacts</i>	51
<i>iii. Key Takeaways</i>	75
<i>04: Conclusions</i>	79
<i>05: Bibliography</i>	83



EXECUTIVE SUMMARY

ES

EXECUTIVE SUMMARY

THE EVOLVING LANDSCAPE OF MASS-MARKET RATE DESIGN

There is a serious conversation unfolding around electricity rate design for mass-market (residential and small commercial) customers—both in the U.S. and internationally. New proposals are appearing for how to improve rates to meet emerging challenges (and opportunities) around environmental impact, customer engagement, bill management, reliability, and cost recovery. These proposals frequently generate debate and conflicting opinions between stakeholders.

RATE DESIGN CHALLENGES

Recent trends are forcing stakeholders across the industry to take stock of how customer needs are evolving and how that affects the electricity system. Customer load profiles are becoming more diverse while new technology is increasing potential customer capabilities.

Existing default rates in the U.S. are simple—typically pairing a flat, volumetric energy rate with a customer charge. These rates have worked well enough but are proving inadequate in the face of recent trends, as they fail to provide price signals that reflect system costs and enable customer response. An expanded rate design toolkit is needed, but it is critical that solutions do not reduce signals for energy efficiency or be difficult for customers to understand and respond to.

POTENTIAL SOLUTIONS

Two types of alternative mass-market rate designs are often proposed to meet rapidly evolving customer needs in the near-term:

- **Time-based rates** can provide more accurate price signals to customers, better reflecting the marginal cost of supplying and delivering electricity. These price signals may lead customers to change their consumption patterns to reduce both peak and total consumption.
- **Demand charge rates** can provide a price signal to reduce peak demand and can potentially allocate peak-driven costs more fairly. Customers may respond by changing their consumption patterns to reduce peak demand, flattening their load profile.

These solutions can be important near-term steps in the ongoing evolution of rate design.

Objectives of This Report

To support informed decision making, this report provides a meta-analysis of numerous existing studies, reports, and analyses to support an objective assessment of the efficacy of time-based rates and demand-charge rates for mass-market customers. The report:

- Provides a structure for utilities, regulators, and stakeholders to design and evaluate time-based and demand charge rates.
- Identifies major design choices required for each rate, and reviews options for those dimensions.
- Identifies whether empirical data confirms (or refutes) the potential benefits of each rate, and notes where clear evidence is not available.
- Determines best practices that can help achieve and maximize desired outcomes.
- Highlights areas where further study is needed.

RESEARCH INSIGHTS ON TIME-BASED RATES

RANGE OF FINDINGS

Our review of industry experience with time-based rates finds that they can reduce customers' peak consumption and total energy consumption without compromising customer acceptance (in terms of enrollment and retention). Empirical evidence shows that time-based rates have the potential to result in:

- Peak load reduction of 0–50%
- Reduction in total energy consumption of 0–10%
- Customer enrollment rates of 6–98% and retention rates of 63–98%

These impacts depend on key choices made in designing the rate.

KEY DESIGN CHOICES THAT INFLUENCE IMPACTS

The impact of time-based rates can vary widely, as evidenced by the wide ranges at left. This variation is influenced by key choices made along nine important design dimensions. Several of these dimensions have a particularly noteworthy effect on the efficacy of the rate:

- **Peak/Off-Peak Price Ratio** is one of the strongest predictors of customer peak load reduction, as higher ratios send a stronger price signal to shift consumption away from peak hours—for instance, time-of-use rates with a 5:1 ratio tend to double the peak reduction compared to a 2:1 ratio.
- **Peak Period Duration** and **Peak Period Frequency** have a significant impact on customer acceptance. Customers are less willing to enroll in a rate, and less able to respond once enrolled, where the peak periods are too long or when critical peak pricing events occur too often.
- The **Financial Mechanism** is a strong driver of peak load reduction. Price-based rates can double the reduction achieved with rebate-based rates, which reward conservation but do not penalize consumption.
- The **Enrollment Method** affects customer acceptance, where opt-in rates attract more-engaged participants, but opt-out (default) rates have enrollment rates 3–5 times higher than opt-in rates, as well as increased peak reduction.
- **Enabling Technology** can substantially increase the peak load reduction by customers. Rates coupled with “active” technologies (which automate customer response) reduce peak load by an additional 10–20 percentage points compared to the same rate without technology.

RESEARCH INSIGHTS ON DEMAND CHARGE RATES

RANGE OF FINDINGS

Our review finds that there is comparatively little industry experience with mass-market demand charges relative to time-based rates. Limited empirical evidence is available to provide insight on the efficacy or impact of demand charges on any desired outcome beyond cost recovery. However, there is a serious debate and much theory about how they may affect customers' peak consumption, total energy consumption, and acceptance. Claims regarding the impact of demand charge rates on these outcomes (positive or negative) are largely speculative. The industry needs to better align on what is currently known and unknown, and where further research will be most useful.

KEY DESIGN CHOICES THAT INFLUENCE IMPACTS

While there is a clear gap in the empirical evidence, our research suggests that there are key design choices that will determine the efficacy of the rate. Of the eight important design dimensions for demand charges (some of which differ from time-based rates), four are likely to be particularly influential:

- The **Cost Components & Allocation** directly determine the magnitude of the demand charge price. Approaches range from including only customer-specific costs (e.g., service transformer) to including all costs associated with system infrastructure built to meet peak demand (e.g., including marginal generation and transmission capacity). The magnitude of the price will impact both peak consumption and customer acceptance, depending on whether customers are able to change behavior in response to the rate.
- **Peak Coincidence** can provide a more-targeted price signal, where charges coincident with system peak may help customers understand when to reduce their demand. In contrast, noncoincident charges are assessed against customer demand at any time, regardless of whether noncoincident demand affects system costs.
- A **Ratchet Mechanism** can help stabilize utility revenue by locking in a floor at a certain level for the customer's demand bill, but the mechanism may remove customers' incentive to reduce peak load, depending on how the ratchet is designed.
- **Enabling Technology** may be the most important determinant of whether customers actually respond to a demand charge price signal. It is possible that sufficiently educated customers will respond by reducing peak demand, but technology that automates their response will reduce the possibility of customers not changing their behavior due to confusion about the rate.

EXECUTIVE SUMMARY

CONCLUSIONS

RESEARCH TAKEAWAYS

- **Specific design choices are key to the efficacy of any time-based or demand charge rate.** In particular, the accuracy of the price signal (e.g., cost components and allocation) and the ability for customers to respond (e.g., peak period duration or a ratchet mechanism) are critical design choices.
- **In theory, it may be possible to achieve similar objectives using either time-based rates or demand charges, but this remains unproven.** Proposals often state similar objectives, including recovering costs while sending price signals that better reflect the drivers of those costs. However, it is unclear whether the two rate designs send equally effective price signals—more evidence on the impacts of demand charges is needed.
- **Regulators and utilities considering these alternative rates should incorporate identified best-practice design principles.** Evidence shows effective time-based rates—particularly time-of-use rates—can be developed and widely deployed using design choices described in this report. While there is insufficient evidence on the impacts of demand charges, demonstration and evaluation projects can be implemented to gain experience.
- **Improved mass-market rates for consumption are necessary but not sufficient.** Ongoing attention is also needed to develop improved pricing structures and compensation mechanisms that fairly represent the benefits and costs of distributed generation and other distributed energy resources. Although this report focuses exclusively on rates for consumption, a more complete transformation of electricity pricing will also include accurate and fair value pricing for on-site generation and similar customer-provided grid services.

FUTURE RESEARCH NEEDS

There are significant knowledge gaps related to both time-based and demand charge rates that the industry and researchers should address. Specific topics that emerged through this work include:

- **Evaluating rate impacts on total energy consumption**
- **Identifying the impact of demand charges on key outcomes**
- **Improving understanding of the relationship of rates and technology**
- **Clarifying methods for including and allocating cost components**

Looking Ahead

Moving toward time-based or demand charge rates is an important step in the evolution of more-sophisticated rates. While near-term improvements are critical, it is also important that the industry stay focused on longer-term goals for rate design. This can include:

- **Transitioning more-sophisticated rates from opt-in to default, as California is doing with time-of-use rates, and exploring opportunities to further evolve rate sophistication, such as by combining time-based and demand charge rates.**
- **Developing new rates that provide greater pricing granularity to better signal value and enable response, both through behavior and with technology.**
- **Developing new ways to manage the tension between maintaining a minimally complex customer experience and continuing to increase rate sophistication.**

01

CONTEXT



01: CONTEXT

States across the country are facing the challenge of adapting mass-market rate designs to meet rapidly evolving customer needs

EVOLVING TRENDS

Recent trends have forced stakeholders across the industry to take stock of how customer needs are evolving and how that affects the electricity system:*



DIVERSITY OF LOAD PROFILES IS INCREASING

“Customers will have more individuated load profiles, and any disparate impacts of applying a homogeneous rate to an increasingly heterogeneous customer class will become more pronounced.” [33]



NEW TECHNOLOGY IS INCREASING CAPABILITIES

“...changes in the grid and technology have expanded the ability of...consumers to evaluate and respond to rates...changes have also shifted costs to a subset of customers who are unable to employ new technologies.” [47]

IMPLICATIONS FOR RATE DESIGN

Existing default rates for mass-market customers are, nearly universally, a simple combination of a flat volumetric energy rate and a fixed customer charge. This approach has worked up to now, but in the face of recent trends these rates are proving inadequate:



CURRENT PRICE SIGNALS ARE INADEQUATE

“...most electricity customers...do not have the information or the incentive to change their electricity consumption in response to the frequent variation in electricity system costs.” [42]

THE EXISTING RATE DESIGN TOOLKIT IS LIMITED

“A better balance could likely be achieved if the rate design toolkit were expanded beyond just fixed charges and per-kWh charges.” [33]

* As used in this report, the term mass-market customers includes residential and small commercial customers.

01: CONTEXT

Rate designs discussed in this report represent incremental solutions to these challenges, and are part of a long-term evolution of rates

MOVING TOWARD MORE-SOPHISTICATED RATES

As RMI's Electricity Innovation Lab (e-Lab) outlined in the 2014 report *Rate Design for the Distribution Edge*, the level of rate sophistication can increase over time to accommodate changing customer and system needs.

This report focuses on the first step in this evolution: moving from traditional rates to moderately sophisticated rates. However, while this is a critical near-term step, it is important to keep in mind that it is part of the larger transformation to high sophistication rates.

WHAT IS SOPHISTICATION?

Rate sophistication can be increased along three continuums:

- **Attribute Continuum**—where rates can unbundle and separately price the various sources of benefit and cost (e.g., energy, capacity, etc.).
- **Temporal Continuum**—where rates can evolve from unchanging flat rates to include time-differentiated prices that reflect benefits and costs that vary by time.
- **Locational Continuum**—where price signals can shift from standard, system-wide values to prices that reflect site-specific benefits and costs.

While increasing the sophistication of rates can help adapt to the evolving electricity system and customer needs, this must be balanced against established rate design principles (see page 13).

This report focuses on the first steps in an evolution: the alternatives in the shaded cells.

NEAR-TERM DEFAULT OR OPT-IN POSSIBILITIES	LONGER- TERM, MORE SOPHISTICATED POSSIBILITIES
Time-of-Use Pricing	Real-Time Pricing
Energy + Capacity Pricing (i.e., demand charges)	Attribute-Based- Pricing
Distribution “Hot Spot” Credits	Distribution Locational Marginal Pricing

Source: [32]

01: CONTEXT

Utilities and advocates have commonly proposed two types of rates as potential near-term solutions

COMMONLY PROPOSED RATE SOLUTIONS

This report explores two prominent and often proposed mass-market rate design alternatives: *time-based rates** and *demand charge rates*. Both rates moderately increase sophistication from traditional rates, and are proposed to accomplish similar goals: recover costs while providing a price signal that better reflects the behaviors that drive system costs.

1. Time-Based Rates

What are they?

A rate that varies by time of day to more accurately reflect costs, designed to encourage customers to participate in reducing overall system costs or achieve other goals.

Why are they proposed?

Current rates do not accurately signal the cost of providing electricity at a given moment in time—this results in customers using electricity indiscriminately at high-cost times, and increasing total system cost.

How might they help?

Time-based rates can provide more accurate price signals to customers, better reflecting the marginal cost of supplying and delivering electricity. These price signals may lead customers to change their consumption patterns to reduce both peak and total consumption.

2. Demand Charge Rates

What are they?

A rate that incorporates a demand charge—for example, assessed on a per kW basis—in place of some portion of the volumetric energy and fixed customer charges.

Why are they proposed?

Current rates do not signal to customers that their power demand—in addition to energy consumption—creates costs. As a result, customers do not have an incentive to reduce power draw at peak system loading, which increases long-term capacity costs.

How might they help?

Demand charges can provide a price signal to reduce maximum demand, and potentially allocate peak-driven costs more fairly. Customers may respond by changing their consumption patterns to reduce peak, flattening their load profile.

* This report adopts the term *time-based rates*. As defined by the U.S. Department of Energy, *time-based rates* “...range from *time-of-use* to *real-time pricing* and are frequently referred to with terms such as *time-differentiated retail rates*, *time-variant pricing*, *advanced pricing programs*, and *time-varying retail pricing*. We refer to all of these as *time-based rate programs*—in which prices vary over time and different prices are in effect for different hours on different days.”

01: CONTEXT

As new rates are considered, they must be reconciled with established rate design principles

The development of mass-market rates is guided by foundational rate design principles, set forth through seminal works in the mid-20th Century by authors including James Bonbright, Paul Garfield, and Wallace Lovejoy. Revised principles have been proposed by organizations including Rocky Mountain Institute, the Regulatory Assistance Project, and the New York Department of Public Service to reflect 21st Century conditions [6, 22, 32, 33]. These various sets of principles can be boiled down to the following guidelines:

- **Enable cost recovery**, so that the utility can continue to provide reliable service with a low cost of capital for any needed economically efficient investments.
- **Reflect cost causation**, accurately incorporating the impact of customers' use on system cost of service, and considering both embedded costs and long-run marginal and future costs.
- **Encourage decision-making**, that is well-informed and economically efficient.
- **Support desired outcomes**, in a technology-neutral manner, including energy efficiency, peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts.*
- **Provide transparency**, so that any incentives or subsidies should be explicit, transparent, and support policy goals.
- **Provide fair value**, both for services provided by the grid and services from the customer.
- **Customer-orientation**, so that the customer experience is practical, simple, and understandable.
- **Maintain stability**, such that customers' bills are predictable, even if the underlying rates use dynamic price signals.
- **Ensure access**, so that vulnerable customers have access to affordable electricity.
- **Practice gradualism**, so that changes to rate design do not cause large, abrupt increases in bills.

Historically, some of these principles (such as cost recovery) have carried more weight than others in the rate design process. While this is beginning to change, there are several principles that remain in tension with each other, such as encouraging decision making (i.e., behavior change) while maintaining stability and enabling cost recovery. This tension must be managed as new rates are developed.

**While rates should be technology-neutral in principle, in reality this is sometimes overruled by policies adopted at the federal, state, and local levels.*

01: CONTEXT

Critical questions remain regarding the application and impacts of time-based and demand charge rates

KEY QUESTIONS

1. What design choices are most important?
2. What magnitude of impact can the rates have on customer behavior?
3. Do the rates risk unintended consequences from customers' behavioral response?
4. What might prevent implementation of these rates?

Additional concerns outside the scope of this research will also be critical to consider as rates are developed, including:

- What are the bill impacts of rates, especially on low-income customers?
- How can utilities manage risks associated with the rate design?
- Is the utility business model compatible with the rate design?
- What marketing and outreach strategies can help make the rate most successful?

RESEARCH SCOPE

Objectives

- Provide a structure for utilities, regulators, and stakeholders to design and evaluate time-based and demand charge rates.
- Identify major design choices required for each rate, and review options for those dimensions.
- Identify whether empirical data confirms (or refutes) the potential benefits of each rate.
- Determine best practices that can help achieve and maximize desired outcomes.
- Highlight areas where further study is needed.

Considerations

We do not present new research, but rather provide a meta-analysis of dozens of existing studies, reports, and analyses to support an objective assessment of the efficacy of these rate designs. Wherever possible, we highlight empirical evidence that exists, and where strong empirical results are not available we note this lack of clear evidence and do not draw definitive conclusions.

01: CONTEXT

Within these objectives, this research is constrained to focus on a subset of all possible time-based and demand charge rates

THIS RESEARCH IS LIMITED TO:

- **Mass-market customers.** This predominantly includes residential customers—a significant share of customers and of total load, most of whom do not currently have rates that send adequate price signals.
- **Rates for electricity consumption.** We focus on rates charged for consumption—while important, we do not consider issues of compensation for distributed generation (e.g., net energy metering).
- **Common variations of each rate design type.** For time-based rates in particular, we focus primarily on time-of-use (TOU) rates rather than real-time pricing and variations of flat or inclining-block rates.
- **Impact on three primary desired outcomes: reduction in total energy consumption, peak load reduction, and customer acceptance.** While we focus on these outcomes, the rates may also support other desired outcomes such as system cost reduction, improved grid resilience and flexibility, and reduced environmental impacts.

In addition, the research assumes that necessary metering and grid infrastructure is in place. This is not yet the case everywhere in the U.S., but for purposes of this research we do not limit our scope by considering limitations imposed by traditional metering technology.

Why Not Fixed Charges?

Proposals to add or increase fixed charges (mandatory fees regularly assessed on a per customer basis) have proliferated in recent years, with proponents arguing they are needed to provide revenue certainty and ensure customers “pay their fair share” of system costs.

However, fixed charges are not a solution to the evolving rate design challenges outlined here. Fixed charges decrease the level of rate sophistication, when more is needed. In addition, numerous studies have shown that fixed charges disproportionately impact low-/fixed-income customers and other low-use customers, and remove incentives for customers to reduce energy consumption or peak demand. For more information on fixed charges we direct the reader to other reports that detail their impacts, including [4, 9, 11, 28, 38].

A city skyline at sunset with a large white box containing text. The sun is a bright yellow circle in the upper right, and the sky is a gradient of orange and red. The city buildings are silhouetted against the sky. A white rectangular box covers the left and center of the image, containing text and a large number.

RESEARCH INSIGHTS
TIME-BASED RATES

02

02: RESEARCH INSIGHTS: TIME-BASED RATES

i. TYPES OF TIME-BASED RATES

For clarity, this section provides a streamlined overview of the distinct types of time-based rates.

ii. DIMENSIONS OF TIME-BASED RATES

iii. KEY TAKEAWAYS

02: RESEARCH INSIGHTS: TIME-BASED RATES

As of 2014, time-based rates—basic and with modifications—were offered in nearly all states, though adoption remains low

ILLINOIS

ComEd

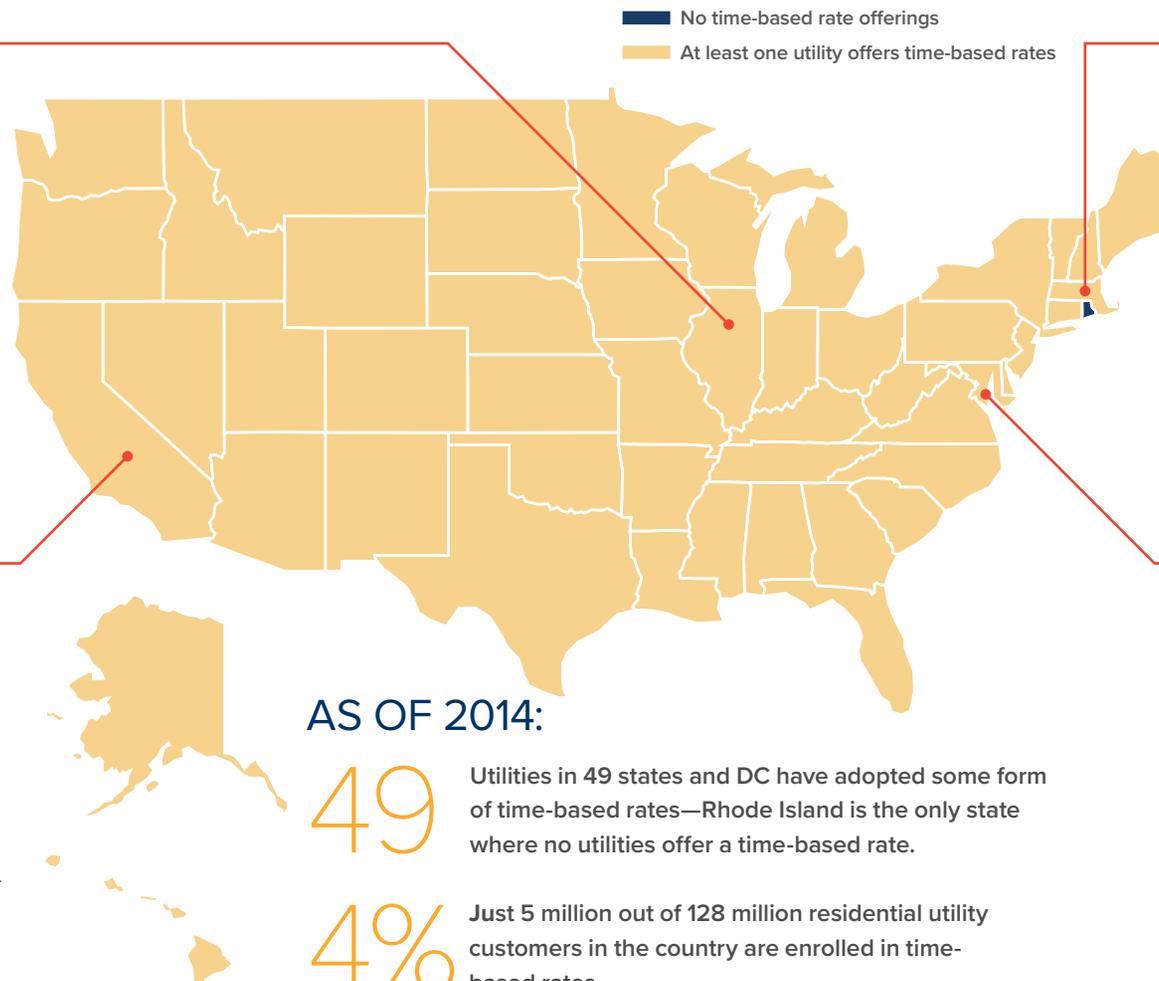
ComEd's Hourly Pricing program is one of two programs in the US that bills customers based on hourly wholesale prices. About 10,500 customers are currently enrolled in this program.

CALIFORNIA

SDG&E, PG&E, and SCE

In 2015, the California Public Utilities Commission ordered the state's three investor-owned utilities to implement default time-of-use rates by 2019. All three utilities currently offer voluntary time-of-use rates.

Data Sources: [3, 47, 14, 37]



MASSACHUSETTS

National Grid

Like California, Massachusetts is also planning a transition to default time-based rates. National Grid currently offers delivery-related basic TOU rates to residential customers. The supply portion is billed separately.

MARYLAND

Baltimore Gas & Electric

BG&E's Smart Energy Rewards and PeakRewards rebate-based rates reward reductions in consumption on critical days, and have proven very popular, with more than half of the state's residential customers enrolled.

02: RESEARCH INSIGHTS: TIME-BASED RATES

Time-based rates are built upon one of three structures, which may then be modified further

BASE STRUCTURES

Any time-based volumetric rate design will have one of these structures as a foundation



While not a time-based rate on its own, a **flat** volumetric rate—including inclining block rates—can be considered time-based when coupled with a time-based modification (see right).



A **time-of-use (TOU)** structure reflects historical temporal variation in system costs by differentiating prices by time of day. Both prices and their applicable time period are predetermined.



A **real-time pricing (RTP)** structure provides prices that vary over short intervals (e.g., hourly) to closely (or exactly) reflect actual costs. Prices are not predetermined.

MODIFICATION OPTIONS

These mechanisms can be added to a base structure to increase rate sophistication without moving to a more complex base structure



Critical peak (CP) mechanisms charge customers higher prices or provide a rebate for a limited number of days each year, when system costs are highest.* The price is predetermined, as are the allowable time periods, but the actual peak events are finalized a few hours to a day in advance.



Variable peak (VP) mechanisms apply variable pricing or rebates to peak periods.** In VP, the peak periods are predetermined but the price can vary, for example, according to wholesale prices or reliability needs.



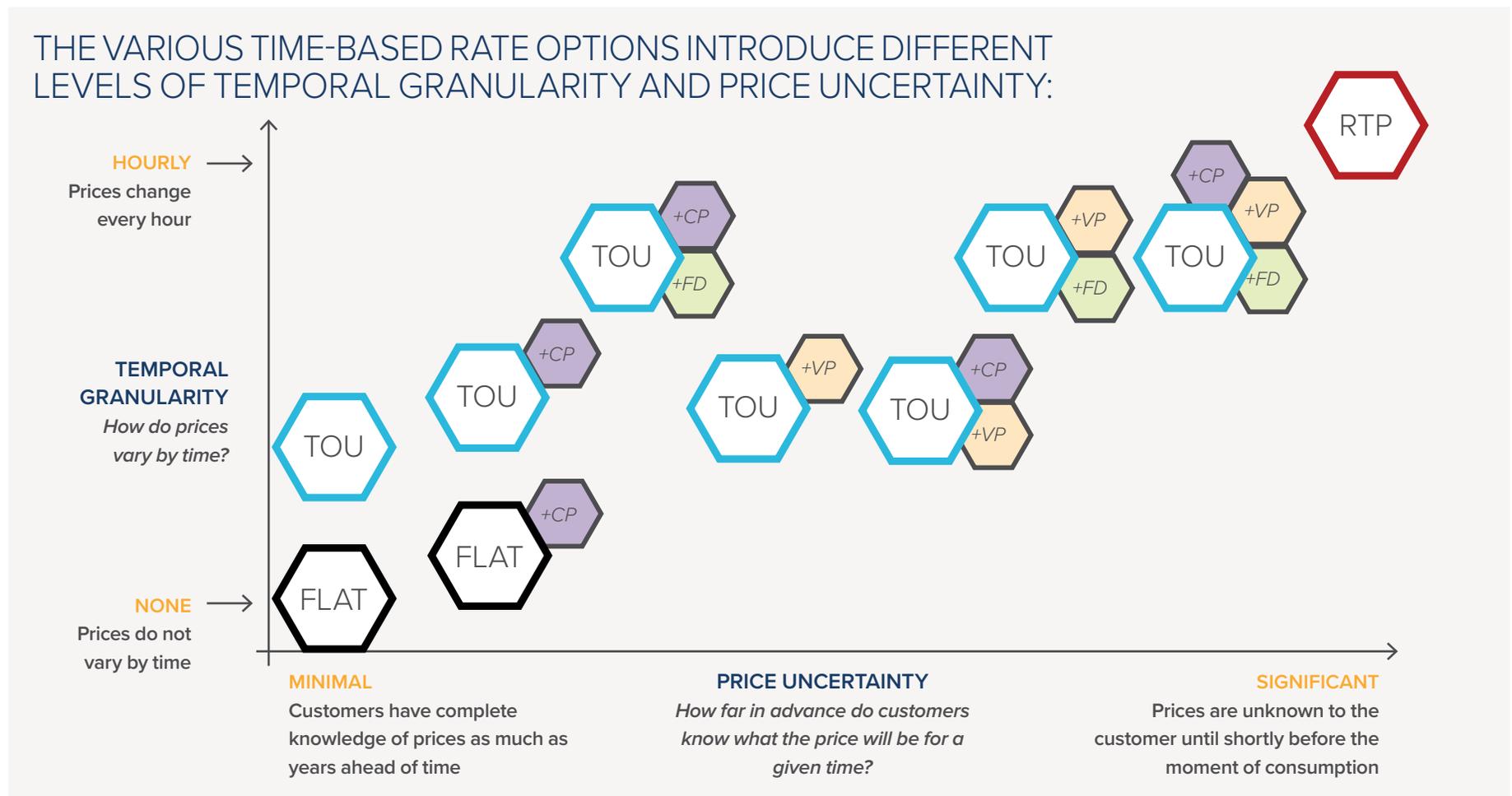
A **flexible duration (FD)** mechanism can be added to a CP or VP program, and uses peak periods that are not predetermined—this is intended to create a closer match between the actual timing of peak system costs and the signal sent to customers.

* Common implementations include critical peak pricing (CPP) and critical peak rebates (CPR), also known as peak time rebates (PTR).

** Common implementations include variable peak pricing (VPP) and variable peak rebates (VPR).

02: RESEARCH INSIGHTS: TIME-BASED RATES

These structures and modifications produce an array of time-based rate designs that increase sophistication from traditional flat rates



02: RESEARCH INSIGHTS: TIME-BASED RATES

i. TYPES OF TIME-BASED RATES

ii. DIMENSIONS OF TIME-BASED RATES

This section outlines the major components of a time-based rate and follows with detailed research on the potential options for each dimension and their implications

iii. KEY TAKEAWAYS

02: RESEARCH INSIGHTS: TIME-BASED RATES

Design choices are required along each of nine dimensions for any time-based rate



PRICING FOUNDATION

- 1. Cost Components & Allocation** What are the specific costs recovered through the rate, and how are they allocated across time periods?



STRUCTURE

- 1. Peak/Off-Peak Price Ratio** What is the ratio of the price charged for peak period consumption to that charged for off-peak consumption?
- 2. Peak Period Duration** What is the timing and length of the period(s) where consumption is billed at a higher rate?
- 3. Peak Period Frequency** How often do the peak time periods occur?
- 4. Number of Pricing Periods** How many intraday time periods have distinct pricing levels?
- 5. Seasonal Differentiation** How many seasons (i.e., sets of months) have distinct rates?
- 6. Financial Mechanism** Does the rate use a price or rebate to communicate to customers the cost/benefit of consumption at a given time?



IMPLEMENTATION

- 1. Enrollment Method** What strategy is used to enroll customers in the rate design program (e.g., opt-in or opt-out)?
- 2. Enabling Technology** What hardware and/or software is included to provide actionable information on consumption or prices, or automatically control load in response to price signals?



PRICING FOUNDATION

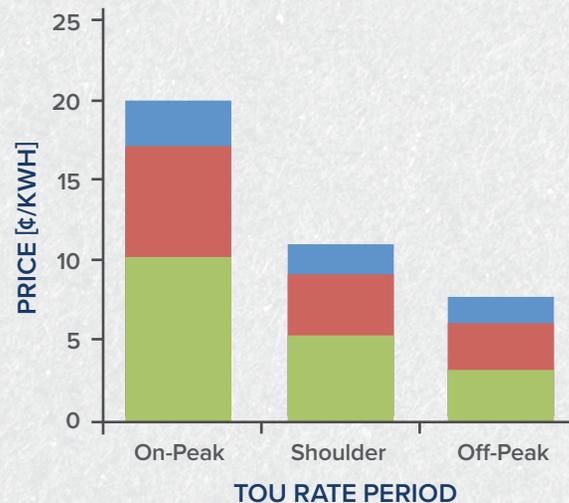
#1: COST COMPONENTS & ALLOCATION

Well-designed time-based rates better allocate time-varying costs to prices for consumption to time intervals that drive those costs

DEFINITION

The specific cost components to be recovered through the time-based rate, and the allocation of those costs into time periods.

ILLUSTRATIVE TOU COST ALLOCATION



■ T&D Capacity
■ Generation Capacity
■ Energy

KEY TAKEAWAYS

- Assigning both energy- and demand-related costs to the time they are incurred brings rates closer to the anticipated marginal costs during each period.
- The selection and allocation of cost components affect the magnitude of costs in each time period, which in turn affects the peak/off-peak price ratio and influences customer behavior.



PRICING FOUNDATION

#1: COST COMPONENTS & ALLOCATION

The process of selecting and allocating cost components can assign most marginal and peak-driven costs to the rate's peak period(s)

PROCESS & OPTIONS

(A review of the full process of determining cost allocation among customer classes and the subsequent calculation of rates is beyond the scope of this report. For a discussion of these issues, see [22] and [24])

Selecting Cost Components

- Specific cost components to include in a time-based rate are selected based on the utility's cost classification, which often separates costs on a demand or energy basis:
 1. Energy-related costs, such as fuel and variable operating costs, baseload generation, and associated transmission and distribution infrastructure.
 2. Demand-related costs, such as peaking generation and additional transmission and distribution capacity needed to meet peak demands.

Allocation to Periods

- Prior to allocating costs, the rate's peak period(s) need to be defined, based on characteristics and objectives at the appropriate level of the system (e.g., bulk, distribution).
- Cost components are then allocated to the appropriate periods:
 - Most marginal capacity costs can be allocated to the peak (and shoulder) periods, with little to none allocated to the off-peak period.
 - Costs that are not peak-driven, including baseload generation and distribution infrastructure costs, can be allocated to off-peak periods, or distributed across periods.
- In some cases, adjustments can be made to align price signals with desired outcomes.
 - For example, some portion of baseload or fixed costs might be allocated to peak periods in order to have higher on-peak prices that will encourage desired customer response.



STRUCTURE

#1: PEAK/OFF-PEAK PRICE RATIO

A time-based rate's peak to off-peak price (POPP) ratio is one of the strongest predictors of reduction in peak customer demand

DEFINITION

The ratio of the price charged for peak-period consumption to the price charged for off peak-period consumption, where higher numbers indicate a stronger price signal to shift consumption away from peak hours.

OPTIONS

The range of POPP ratios have varied widely in practice and differ depending on the structure:

- **Basic Time-Based Rates:** POPP ratios are typically between just above 1:1 and 7:1. [16]
- **Modified Time-Based Rates:** rates with a critical-peak period (which is applied to a small number of hours each year) typically have much higher POPP ratios, ranging from 4:1 to 20:1. [16]

KEY TAKEAWAYS

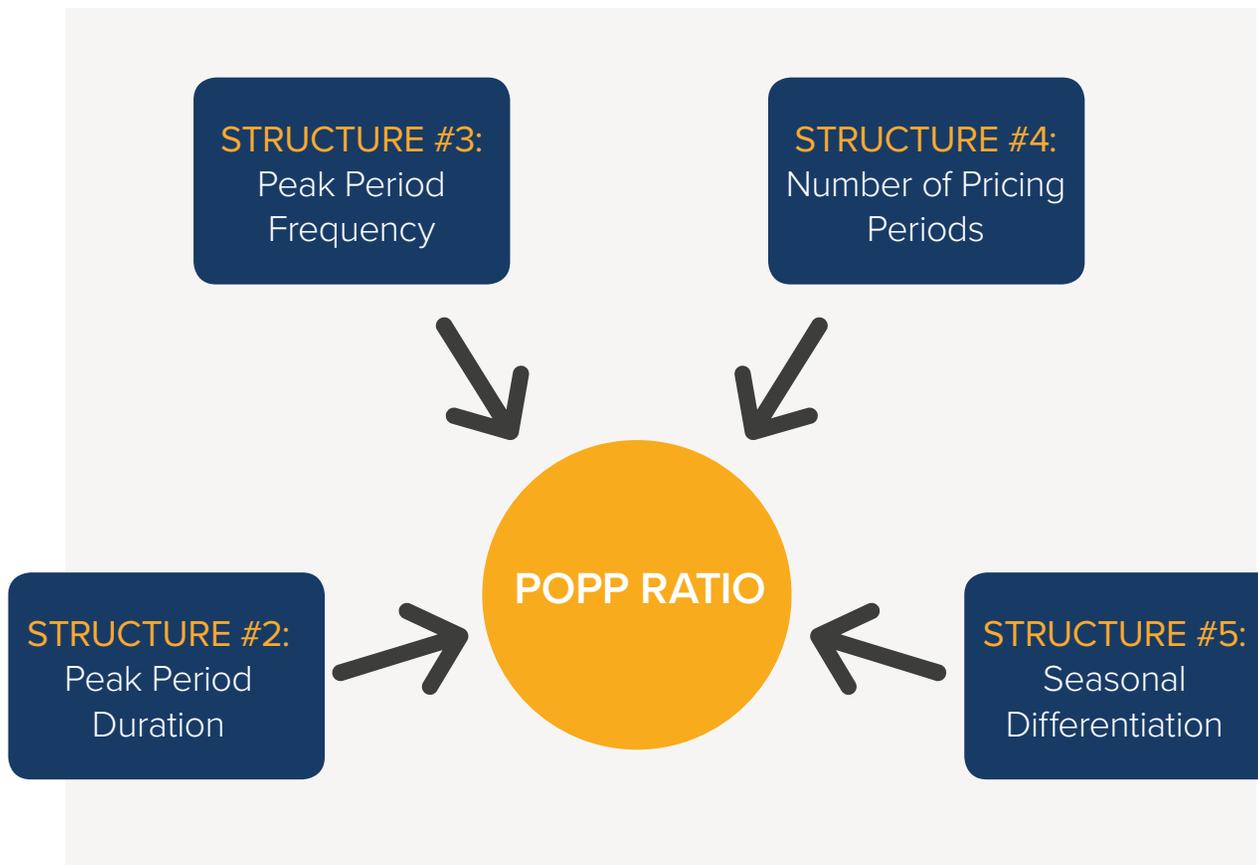
- POPP ratios are strongly correlated with customer peak reduction, though the impact may taper off at higher values.
- There is some evidence suggesting that a higher POPP ratio may result in greater reductions in energy consumption, but industry experience is insufficient to draw firm conclusions.
- Customer acceptance may suffer slightly at very high POPP ratios, but evidence is limited.



STRUCTURE

#1: PEAK/OFF-PEAK PRICE RATIO

The POPP ratio is primarily a function of four other dimensions, which can be adjusted to achieve the desired ratio



SETTING THE PEAK/OFF-PEAK PRICE RATIO

- The POPP ratio is not directly specified as it is the result of four other structural dimensions: peak period duration, peak period frequency, number of pricing periods, and seasonal differentiation.
 - These dimensions and considerations that inform their values are discussed in detail throughout this section.
- However, given the significant impact that the POPP ratio can have, it is useful to target a specific ratio.
- A desired POPP ratio can be achieved by iteratively adjusting the value of the four input variables.



STRUCTURE

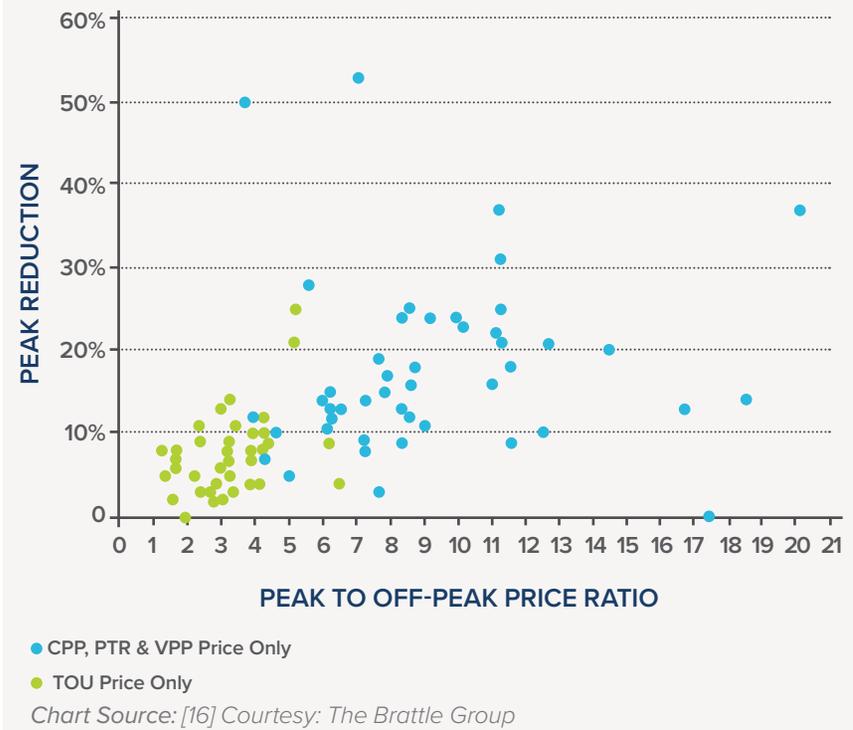
#1: PEAK/OFF-PEAK PRICE RATIO

Experience with time-based rates shows that customers further reduce on-peak consumption in response to stronger POPP ratios

IMPACT ON OUTCOMES

- **Peak reduction** is strongly correlated with the POPP ratio, though some studies suggest diminishing returns from higher ratios. Specifically:
 - With **Basic Time-Based Rates**, a 2:1 ratio tends to produce peak reduction of ~5%, vs. ~10% from a 5:1 ratio. [16]
 - In **Modified Time-Based Rates**, a 5:1 ratio tends to result in ~14% peak reduction, vs. ~16% for a 10:1 ratio. [16]
- A higher ratio can typically be used in a modified time-based rate because it applies to a shorter single duration or a shorter total duration.
- While there are outliers that deviate from these general trends, this is likely due to the specific customers participating in that rate—the enrollment process and customer characteristics can affect peak reduction impacts significantly. [16]

PEAK-REDUCTION IMPACT BY POPP RATIO





STRUCTURE

#1: PEAK/OFF-PEAK PRICE RATIO

Few studies have evaluated changes in total energy consumption under time-based rates, but some evidence indicates that higher POPP ratios can increase the reduction in energy consumption

IMPACT ON OUTCOMES

- **Reduction in Total Energy Consumption** may increase with higher POPP ratios:
 - **Basic Time-Based Rates** can induce reduction in total energy consumption, ranging from ~1% to 9% depending on the peak price. [21, 29]
 - **Modified Time-Based Rates** may induce slightly greater conservation, but few studies have considered this. In one of the only studies directly comparing the two, SMUD found that customers on CPP rates with an in-home display (IHD) reduced their monthly consumption by up to 3.5% (versus ~1% for standard TOU rates). [29]

SMUD ENERGY CONSUMPTION IMPACT BY RATE DESIGN

RATE DESIGN	POPP (BASE USAGE)	REDUCTION IN TOTAL MONTHLY CONSUMPTION	
Opt-in TOU, No IHD Offer	3.2	1.1%	(not statistically significant)
Opt-in TOU, IHD Offer	3.2	0.9%	(not statistically significant)
Default TOU, IHD Offer	3.2	1.3%	
Opt-in CPP, No IHD Offer	8.8	-1.0%	(not statistically significant)
Opt-in CPP, IHD Offer	8.8	3.5%	
Default CPP, IHD Offer	8.8	2.6%	
Default TOU-CPP, IHD Offer	3.7 / 10.4	1.3%	(not statistically significant)

Data Source: [29]



STRUCTURE

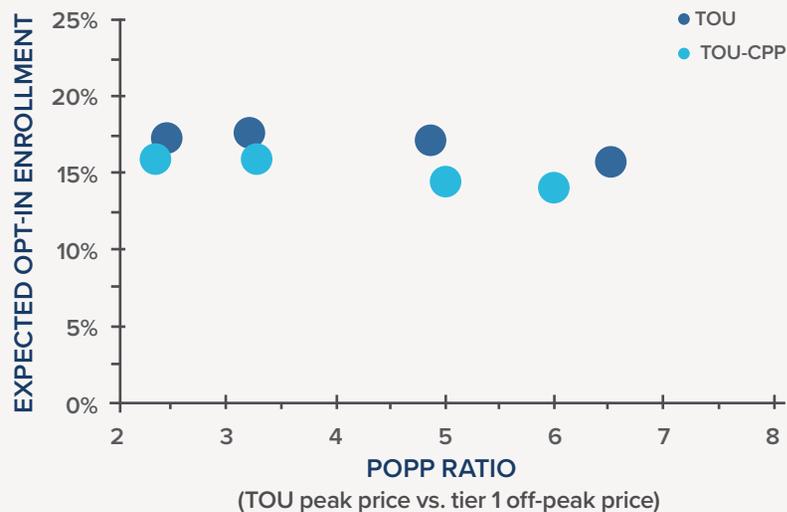
#1: PEAK/OFF-PEAK PRICE RATIO

Customers may be less likely to accept a rate design with higher POPP ratios, but evidence is limited

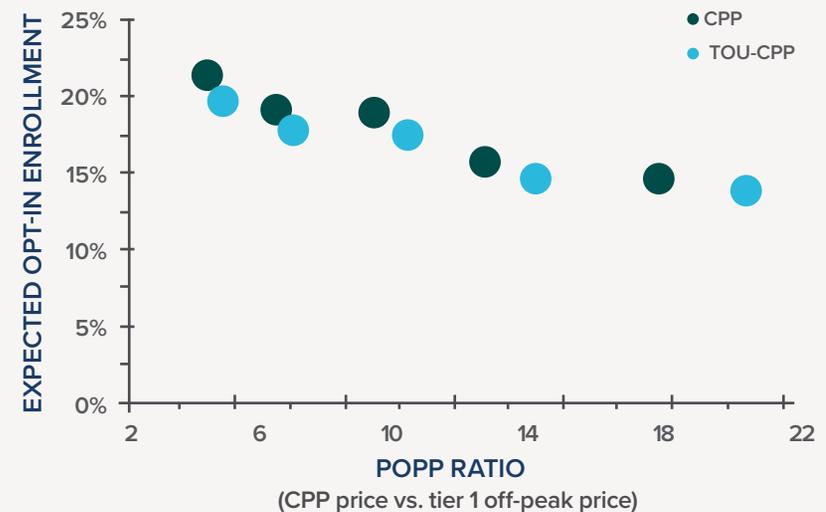
IMPACT ON OUTCOMES

- **Customer acceptance** has been shown to decline slightly when higher POPP ratios are used. Evidence includes:
 - Customer surveys by PG&E show a preference for adjusting other dimensions (such as longer peak-period duration) in exchange for lower POPP ratios. [26]
 - However, modeling results from SMUD's SmartPricing Options pilot found very little difference in enrollment rates for TOU and CPP rate designs under higher POPP ratios (see charts below). [29]

PREDICTED ENROLLMENT FOR TOU RATES BY POPP RATIO FOR SMUD



PREDICTED ENROLLMENT FOR CPP RATES BY POPP RATIO FOR SMUD



Data Source: [29]



STRUCTURE

#2: PEAK PERIOD DURATION

The length of the peak period can be set to correlate with on-peak hours and hours where load reduction is desired in order to achieve system cost reductions or other objectives

DEFINITION

The length of the period(s) during which consumption is billed at a higher rate relative to other periods.

OPTIONS

An acceptable peak period-duration value depends on the choice of the base structure:

- **Basic Time-Based Rates:** have peak period durations ranging from 4 hours to 16 hours. [30, 31]
- **Modified Time-Based Rates:** have similar base peak period durations, while the peak period of the modification (critical peak, variable peak, etc.) may similarly range from 3–16 hours per event. [30, 31]

KEY TAKEAWAYS

- To ensure customers can respond to the price signal, the peak period duration needs to be kept as short as possible while still capturing the necessary peak hours.
 - If the peak period is too long, customers are unable to reduce consumption during the entire period.
 - Customer surveys indicate a preference for a peak period duration not exceeding 4–5 hours, even if that means the peak price will increase. [29]



STRUCTURE

#2: PEAK PERIOD DURATION

The peak period duration needs to be as short as possible while including as many high-cost hours as possible

SETTING THE PEAK PERIOD DURATION

- The objective is to define a period that is short but includes the maximum number of high-cost hours (e.g., hours of expensive generation or system peak). [26]
 - This may also be constrained by other factors, such as customer preference for a shorter peak period.
- The process can be forward looking and consider forecasted hourly cost to identify the cluster(s) of highest-priced hours (see chart below). [26] *

* *Doing so would inherently require regulators to allow utilities to design rates based on a forecasted test year.*

IMPACT ON OUTCOMES

- **Customer Acceptance:** For customers to be able to respond to time-based prices, peak periods cannot be excessively long. For instance, SMUD found that predicted opt-in enrollment would drop by 25–50% if the peak period duration were extended from 3 hours to 6 hours. [29]
- **Peak Reduction:** While the peak period duration contributes to the peak/off-peak price ratio, studies have not quantified the direct effect of peak period duration on peak consumption.

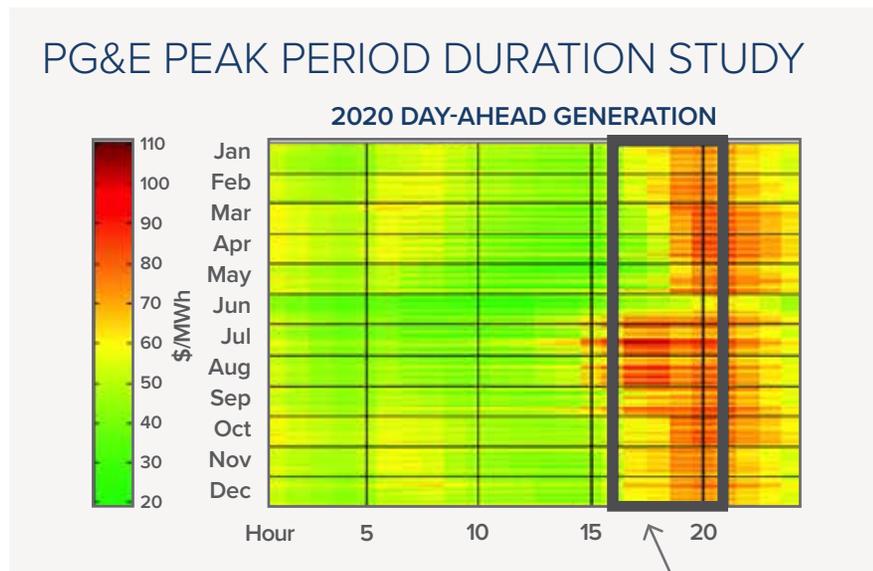
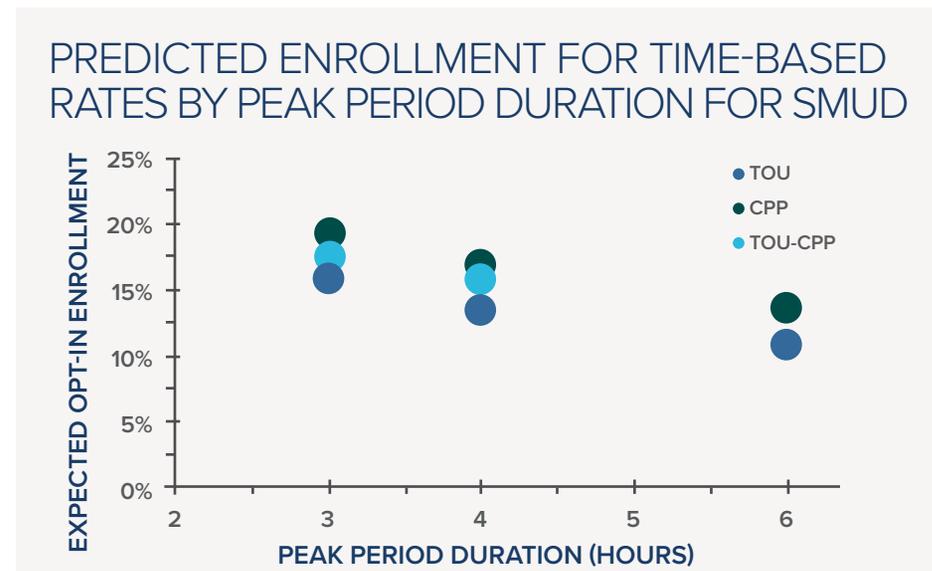


Chart Source: [26]

New Proposed TOU
Peak Period



Data Source: [29]



STRUCTURE

#3: PEAK PERIOD FREQUENCY

The appropriate number of peak periods or events hinges on the type of rate, but is an especially important decision for modified time-based rates

DEFINITION

How often the peak periods or events, when rates are higher relative to other periods, occur.

OPTIONS

The frequency of peak periods or events depends on the base structure:

- **Basic Time-Based Rates** have peak periods that occur regularly, usually daily or every weekday.
- **Modified Time-Based Rates** typically cap the number of peak events at 5–22 days per year (e.g., for CPP and VPP rates). [30, 31]

KEY TAKEAWAYS

- For modified rates that use critical peak pricing, customer enrollment may decline if too many critical peak events are allowed. [29]
- Conversely, utilities have struggled to accurately predict critical peak events for targeting system peak, and increasing the annual number of critical peak events could be considered. [31]

02: RESEARCH INSIGHTS: TIME-BASED RATES



STRUCTURE

#3: PEAK PERIOD FREQUENCY

Determination of peak period duration needs to balance system needs and customer behavior

SETTING THE NUMBER OF EVENTS

- To ensure customer acceptance, critical peak rates limit the number of peak events each year.
 - However, utilities may not accurately predict the actual peak days, decreasing the potential benefit from reducing peak load (and cost). For example, from 2009–2011, 42% of events called by PG&E's SmartDays program did not align with system peak days. [7]
- In the future, critical peak rates may need to relax or remove annual limits on the number of events.
 - To negate utilities' incentives to call frequent events, the rate could proportionally discount shoulder hours around the peak event.

IMPACT ON OUTCOMES

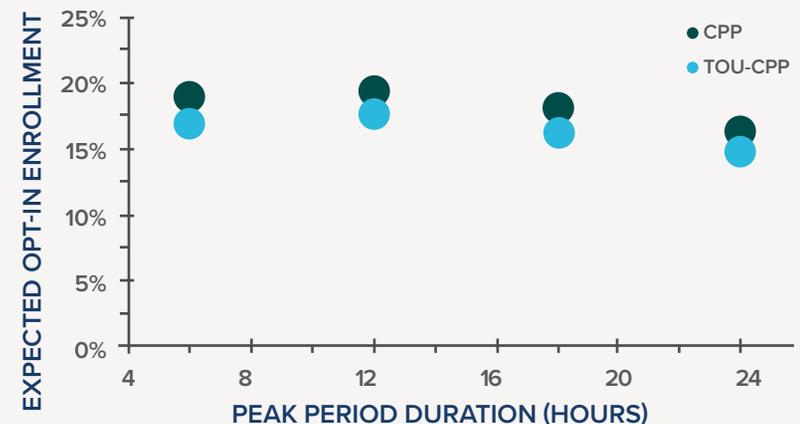
- **Customer Acceptance:** Enrollment in modified time-based rates may suffer if peak periods occur too frequently. For example, SMUD found that increasing the number of critical peak events from 12 to 24 would reduce opt-in enrollment by 2–4 percentage points (due to customers perceiving greater risk). [29]
- **Peak Reduction:** While the peak period frequency contributes to the peak/off-peak price ratio, studies have not quantified its direct effect on peak consumption.

PG&E SMARTDAYS PROGRAM EVENT ACCURACY

YEAR	# EVENTS AVAILABLE	# EVENTS CALLED	# TOP-15 DAYS CAPTURED	% OF TOP-15 DAYS MISSED
2009	15	15	7	53%
2010	15	13	10	33%
2011	15	15	8	47%

Data Source: [7]

PREDICTED ENROLLMENT FOR CPP RATES BY NUMBER OF EVENTS FOR SMUD



Data Source: [29]



STRUCTURE

#4: NUMBER OF PRICING PERIODS

#5: SEASONAL DIFFERENTIATION

The combination of number of pricing periods and number of seasons determines the total number of distinct time periods within a time-based rate design

NUMBER OF PRICING PERIODS

DEFINITION

The number of intraday time periods with distinct and unique price levels, selected to reflect intraday variation in system costs.

OPTIONS

Time-based rates have used 2–4 pricing periods, but most use 3 or fewer. [30]

- For example, Oklahoma Gas & Electric's Smart Study TOGETHER program includes three periods: a critical peak layered on top of a two-segment TOU design. [10]

SEASONAL DIFFERENTIATION

DEFINITION

The number of seasons (i.e., sets of months) with distinct rates, reflecting seasonal variation in the cost of service.

OPTIONS

Time-based rates have included as many as four seasons, but most include only bi-seasonal price variation. [30]

- For example, Nevada Power's NVEnergize rate sets different TOU prices for three seasons: "shoulder summer" (June and September), "core summer" (July and August), and "winter" (October through May). [10]

IMPACT ON OUTCOMES

- **Customer Acceptance:** Some claim that customers will be confused if too many time periods are used (unless enabling technology is provided), but there is no quantitative analysis to substantiate this.
- **Peak and Load Reduction Potential:** The direct effect of either the number of price periods or the number of seasons on peak consumption has not been quantified.
 - However, both contribute to the peak/off-peak price ratio (see page 26)



STRUCTURE

#6: FINANCIAL MECHANISM

Time-based rates may signal customers through both prices and rebates, but they may not be equally effective options

DEFINITION

The type of incentive or disincentive used to communicate to customers the cost or benefit of their behavior at a given time.

KEY TAKEAWAYS

- Evidence indicates that price-based rates result in much greater peak reduction than rebate-based rates. [10]
- Customer acceptance is similar for both price-based and rebate-based rates. [3, 10, 29]
- While rebate-based rates often appeal to policymakers, they introduce challenges that need to be considered:
 - Rebates require an estimate of the customer's baseline consumption, which is difficult for utilities to calculate and also creates an incentive for customers to manipulate their baseline.
 - Rebates provide an asymmetric incentive—a customer may be rewarded for reducing consumption, but is not penalized for over-consumption.
- Despite their flaws, rebates may be useful on a limited basis when targeted at customer segments that are more likely to respond to incentive-style mechanisms than price-based rates. [20]

02: RESEARCH INSIGHTS: TIME-BASED RATES



STRUCTURE

#6: FINANCIAL MECHANISM

Both price-based and rebate-based rates tend to reduce customers' on-peak consumption, but peak reductions from price-based programs are larger and less variable

OPTIONS

Financial mechanisms used by time-based rates fall into two categories:

- **Prices**, where volumetric rates for consumption are increased (or decreased) for certain hours of the day.
- **Rebates**, which provide financial rewards to customers for reducing consumption during the hours that the system is expected to be most stressed.
 - For example, Baltimore Gas & Electric's peak time rebate program provides enrolled customers a \$1.25/kWh rebate for energy reduced below their baseline consumption level from 1–7 pm on event days. [3]

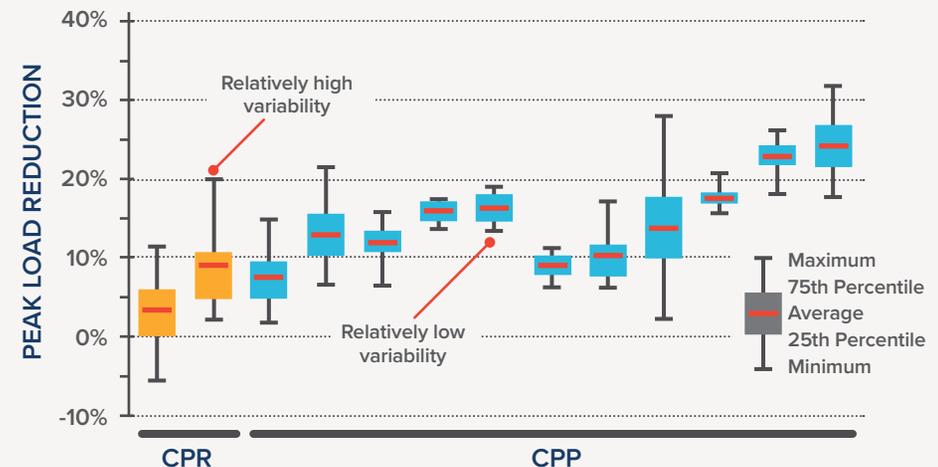
Other noteworthy mechanisms that have been studied but are not appropriate for use in rate design include:

- Competitions and rewards, which recent research suggests could be cost-effective alternatives to rebates. [1, 51]
- Programs based on "moral suasion", which appeal to a person's morals rather than wallet, have proven highly effective in the short run but their impacts do not persist as long as economic incentives. [20]

IMPACT ON OUTCOMES

- **Peak Reduction:** Both price-based and rebate-based rates have been found to result in peak reduction by customers, but the reduction from rebates is typically much lower:
 - Average peak reduction across DOE's Consumer Behavior Study (CBS) utilities was 21% for CPP programs vs. 11% for CPR. [10]
 - Further, DOE found that CPR customers had much greater variability in their peak reduction (see chart). Applying NYISO's methodology, DOE found this variability would reduce the claimed capacity capability by 30% (vs. 10% for CPP). [10]

VARIABILITY OF PEAK REDUCTION: CPP VS. CPR



02: RESEARCH INSIGHTS: TIME-BASED RATES



STRUCTURE

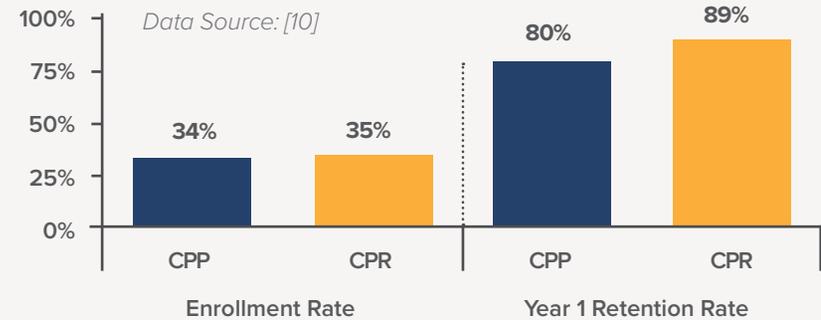
#6: FINANCIAL MECHANISM

Prices and rebates are both well accepted by customers, but rebates may disincentivize reduction in energy consumption

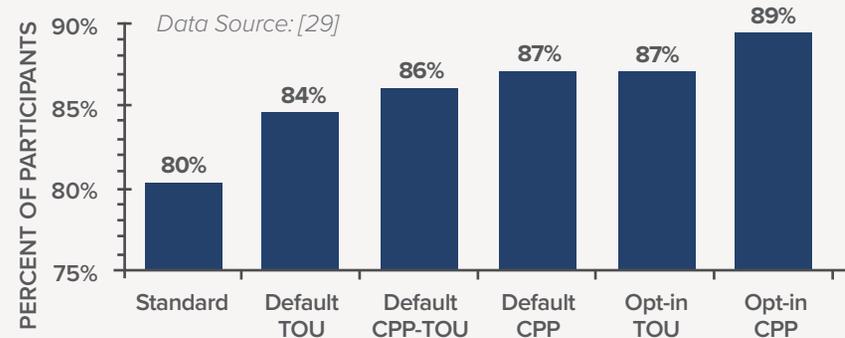
IMPACT ON OUTCOMES

- **Customer Acceptance:** Both price-based and rebate-based rates show high levels of customer enrollment, retention, and satisfaction:
 - Green Mountain Power (GMP) conducted side-by-side studies of price- and rebate-based opt-in rates, finding equivalent enrollment rates and similar retention rates (see chart at upper right). [10]
 - BG&E's PeakRewards Air Conditioning rebate-based opt-in rate, which includes enabling technology, has a 92% customer satisfaction rating. [3]
 - SMUD found CPP customers slightly more satisfied than TOU (in both opt-in and default cases), while both were rated higher than the standard rate (see chart at lower right). [29]
- **Reduction in Total Energy Consumption** for prices and rebates have not been studied. However, research suggests that rebate-based rates can have unintended consequences on total energy consumption:
 - Rebates are provided based on a customer's measured energy consumption relative to an assumed baseline—incentivizing customers to inflate baseline consumption to receive a higher rebate payment.
 - For example, Camden Yards in Baltimore was found to have inflated their demand response program baseline from 2009–10 by turning on the stadium's lights during electricity shortages. [35]
 - Rebates, by themselves, may not incentivize customers to invest in efficiency measures that would impact their baseline or reduce consumption outside the program's peak hours. [8]

GMP CUSTOMER ACCEPTANCE BY FINANCIAL MECHANISM



SMUD CUSTOMER SATISFACTION BY RATE TYPE





IMPLEMENTATION

#1: ENROLLMENT METHOD

Most existing time-based rates enroll customers on an opt-in basis, but greater benefits may be possible using opt-out methods

DEFINITION

The strategy used to enroll customers in a new rate design.

OPTIONS

Enrollment methods include:

- **Opt-in**, where customers can choose to participate but are otherwise not enrolled.
- **Opt-out**, where customers are enrolled by default but have the option to switch to another rate.
- **Mandatory**, where all customers must take service on the rate.*

KEY TAKEAWAYS

- Opt-out time-based rates can garner participation three to five times higher than opt-in enrollment, while having similar retention rates. [41]
- The per-capita response from opt-out time-based rates is typically lower than opt-in programs. [15]
- Opt-out time-based rates can achieve much greater total customer response—while opt-in programs typically enroll only highly engaged customers, opt-out programs also enroll less-engaged customers. [15]

* While less common, some utilities have instituted mandatory enrollment for certain types of customers (e.g., We Energies requires TOU for residential customers who use more than 60,000 kWh annually). [40]



IMPLEMENTATION

#1: ENROLLMENT METHOD

Opt-out rates consistently garner 3–5 times greater enrollment than opt-in rates, with little difference in customer retention

IMPACT ON OUTCOMES

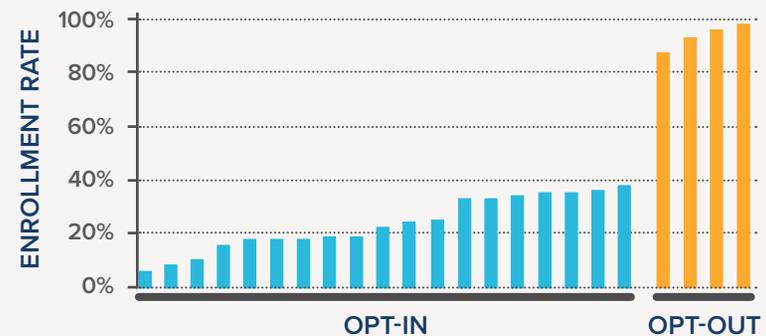
Customer Acceptance

Customers are much more likely to remain on an opt-out rate than enroll in an opt-in one. This is largely due to inertia and the status-quo bias—similar enrollment rates are seen in non-electric rate programs such as insurance plans and organ donation. [15]

- **Opt-In Methods:** A DOE meta-study on time-based rate pilots from 10 utilities found opt-in enrollment rates of 6–38%, with an average of 24%. [45]
 - For **basic time-based rates**, Brattle found enrollment rates of 14–53%, with an average of 28%. [15]
 - For **modified time-based rates**, Brattle found enrollment rates of 2–56%, with an average of 20%. [15]
- **Opt-Out Methods:** A DOE meta-study on time based-rate pilots from ten utilities found opt-out enrollment of 87–98%, with an average of 93%. [45]
 - For **basic time-based rates**, Brattle found enrollment rates of 79–90%, with an average of 85%. [15]
 - For **modified time-based rates**, Brattle found enrollment rates of 77–90%, with an average of 84%. [15]

Charts Source: [10] Charts Courtesy: Lawrence Berkeley National Laboratory

ENROLLMENT RATES IN CBS UTILITY PROGRAMS, BY METHOD



RETENTION RATES IN CBS UTILITY PROGRAMS, BY METHOD





IMPLEMENTATION

#1: ENROLLMENT METHOD

Per-capita peak reduction is lower under opt-out rates, but the total effect is offset by the greater enrollment

IMPACT ON OUTCOMES

Peak Reduction should be considered both on a per-capita basis and in aggregate:

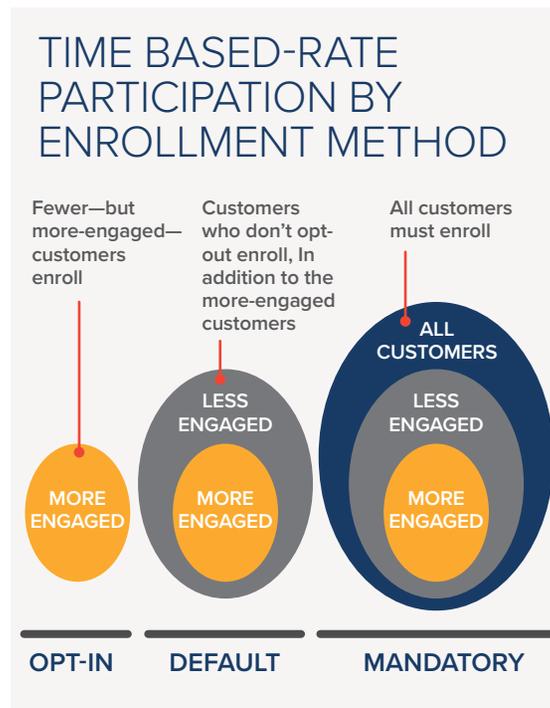
• Per-Capita Impacts

Few studies have directly compared opt-in to opt-out side-by-side. This limited evidence shows opt-in customers to be more engaged:

- **Basic Time-Based Rates:** SMUD found opt-in peak reduction of 12% vs. 6% for opt-out rates, while Lakeland Electric saw 8% for opt-in rates and 0% for opt-out. [10]
- **Modified Time-Based Rates:** SMUD found peak reduction of 25% for opt-in rates vs. 14% for opt-out. [10]

• Aggregate Impacts

- As the per-capita impacts show, the average opt-in customer is more engaged than their opt-out equivalent.
- However, opt-out rates typically enroll all customers that would have joined an opt-in program, plus a large number of less-engaged customers (see figure at near right).
- As a result, aggregate peak reduction from opt-out rates can be much greater than from opt-in rates (see figure at far right). [29]



HYPOTHETICAL PEAK REDUCTION FROM TOU FOR SMUD, BY ENROLLMENT METHOD

	OPT-IN	OPT-OUT*
Enrollment Rate	17%	98%
Peak Reduction	12%	6%
# Residential Customers [16]	543,000	543,000
Avg. Customer Peak Load [16]	2.4 kW	2.4 kW
Aggregate Peak Reduction	27 MW	77 MW

* This assumes that the results from SMUD's pilot are representative and can be extrapolated to all SMUD residential customers.



IMPLEMENTATION

#2: ENABLING TECHNOLOGY

Enabling technology can improve customer peak reduction, but impact and cost effectiveness hinge on the specific type of technology

DEFINITION

Hardware and software—provided with participation in a rate—that provide actionable information on consumption or prices, or automatically controls load in response to price signals.*

OPTIONS

- **Passive technology** includes in-home displays (IHDs) and other technologies that convey signals without taking action, e.g., actual price, price level, or other price indicator.
- **Active technology** includes programmable communicating thermostats (PCTs) and other devices that automatically modulate customer load in response to price or other signals.

KEY TAKEAWAYS

- Enabling technology can improve customer peak reduction—passive technology has had mixed impact, ranging from 0–10 percentage points, while active technologies result in 10–20 percentage points of additional peak reduction. [10, 29]
- Certain passive technologies may have a short useful life—some studies have found that customers tend to stop using passive devices once they have learned the rate information and consumption patterns the device provides. [36]
- In-home displays (IHDs) and programmable communicating thermostats (PCTs) are the technologies that have been studied most extensively to date.
- Future studies are needed to consider alternative technologies as well (e.g., mobile phone apps that provide pricing information). [16, 29, 45]

* Storage technologies and utility-/aggregator-controlled dispatchable resources are not considered here.

02: RESEARCH INSIGHTS: TIME-BASED RATES



IMPLEMENTATION

#2: ENABLING TECHNOLOGY

Experience has shown active technologies to be more effective than passive ones at reducing peak load in response to time-based rates

IMPACT ON OUTCOMES

Peak Load Reduction

There is conflicting evidence on the impact of passive technology, but active technology has proven to consistently and significantly improve peak load reduction:

- **Passive Technology:**
 - A United Illuminating Company pilot found that in-home displays improved peak reduction by 1–15 percentage points. [21]
 - SMUD's SmartPricing pilot evaluation found that IHDs had no effect on demand reduction. [29]
- **Active Technology:**
 - A study across 45 modified time based-rate pilots found programmable, controllable thermostats improved peak reduction by 10–20 percentage points. [45]

PEAK REDUCTION FOR BASIC TIME-BASED RATES – WITH AND WITHOUT ENABLING TECHNOLOGY

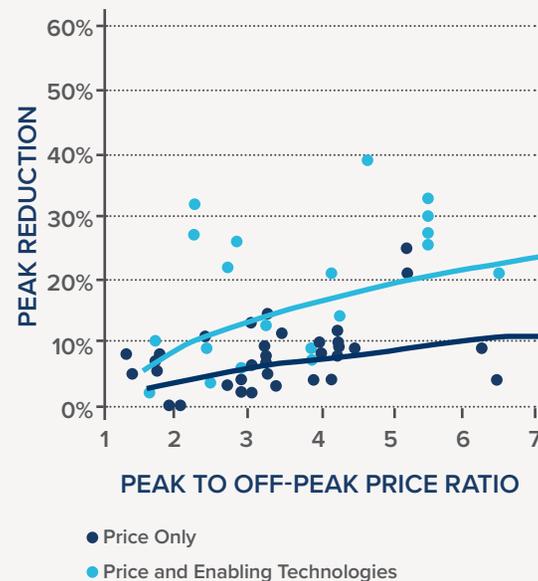


Chart Source: [16] Courtesy: The Brattle Group

PEAK REDUCTION FOR MODIFIED TIME-BASED RATES – WITH AND WITHOUT ENABLING TECHNOLOGY

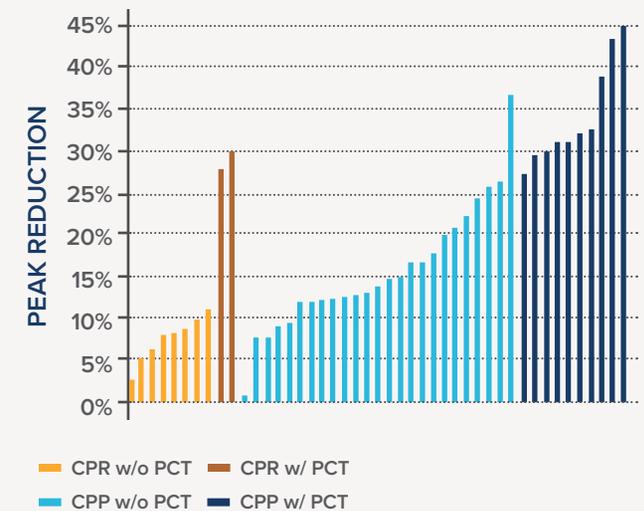


Chart Source: [45] Courtesy: Lawrence Berkeley National Laboratory



IMPLEMENTATION

#2: ENABLING TECHNOLOGY

Experience has shown active technologies to be more effective than passive ones at reducing peak load in response to time-based rates

IMPACT ON OUTCOMES

Customer Acceptance

Passive Technology:

- No observed difference in enrollment or retention between customers with IHDs versus those without in three utility programs as part of DOE's CBS program. [41]
 - SMUD found that less than 20% of the customers that accepted IHDs were using them consistently and roughly 60% of customers that received an IHD never installed it. [29]
 - SMUD also found that many customers used their IHD for limited time, discontinuing use once they learned the rate information and consumption patterns the device provided. [36]

Active Technology:

- DOE's CBS program found average retention rates were similar both with PCTs (~92%) and without (90%). [41]

ACCEPTANCE AND CONNECTION OF IHDs IN THE SMUD SMARTPRICING PILOT

RATE	CUSTOMERS ACCEPTING IHD OFFER	PORTION OF IHDs		
		ALWAYS CONNECTED	SOMETIMES CONNECTED	NEVER CONNECTED
Opt-In CPP	95%	12%	27%	61%
Opt-In TOU	96%	12%	23%	66%
Default TOU-CPP	23%	19%	39%	42%
Default CPP	24%	14%	43%	43%
Default TOU	21%	18%	23%	59%

Data Source: [29]

02: RESEARCH INSIGHTS: TIME-BASED RATES

i. TYPES OF TIME-BASED RATES

ii. DIMENSIONS OF TIME-BASED RATES

iii. KEY TAKEAWAYS

This section provides an overview of the findings from this research and discusses the most important implications for continued consideration of time-based rates

02: RESEARCH INSIGHTS: TIME-BASED RATES

KEY TAKEAWAYS

Industry experience shows that well-designed time-based rates can reduce peak consumption without compromising customer acceptance

- Our review of the industry’s experience with time-based rates finds that they can reduce customers’ peak consumption and total energy consumption without compromising customer acceptance (in terms of enrollment and retention).
- However, the impact of time-based rates can vary widely. Evidence shows that well-designed rates can have significant impact, but also that poorly designed rates can have a negligible impact (which may ultimately be counterproductive).
- This variation is influenced by key choices made along each of the nine design dimensions shown in this report, though several dimensions have a particularly noteworthy effect on the efficacy of the rate. The level of peak reduction is strongly affected by *Peak/Off-Peak Price Ratio*, *Financial Mechanism*, and *Enabling Technology*, while customer acceptance is related to *Peak Period Duration* and *Peak Period Frequency*, and both outcomes are affected by *Enrollment Method*.
- Time-based rates also require thoughtful marketing and customer education to be effective, in addition to good design.

RANGE OF FINDINGS

DESIRED OUTCOME	AVAILABILITY OF EMPIRICAL EVIDENCE	POTENTIAL IMPACT
Reduction in Total Energy Consumption	Few studies have assessed the effect of time-based rates on total energy consumption, but evidence from SMUD and an anonymous northeastern utility shows potential efficiency increases in the single digits.	0–10%
Peak Load Reduction	As one of the primary objectives of time-based rates, this has been heavily studied. Results show a wide range of impacts, depending on the design of the rate.	0–50%
Customer Acceptance	This can be evaluated in terms of enrollment rates and retention rates, which are well studied, particularly by the ten utilities in DOE’s recent Consumer Behavior Study.	Enrollment: 6–98% Retention: 63–98%

02: RESEARCH INSIGHTS: TIME-BASED RATES

KEY TAKEAWAYS

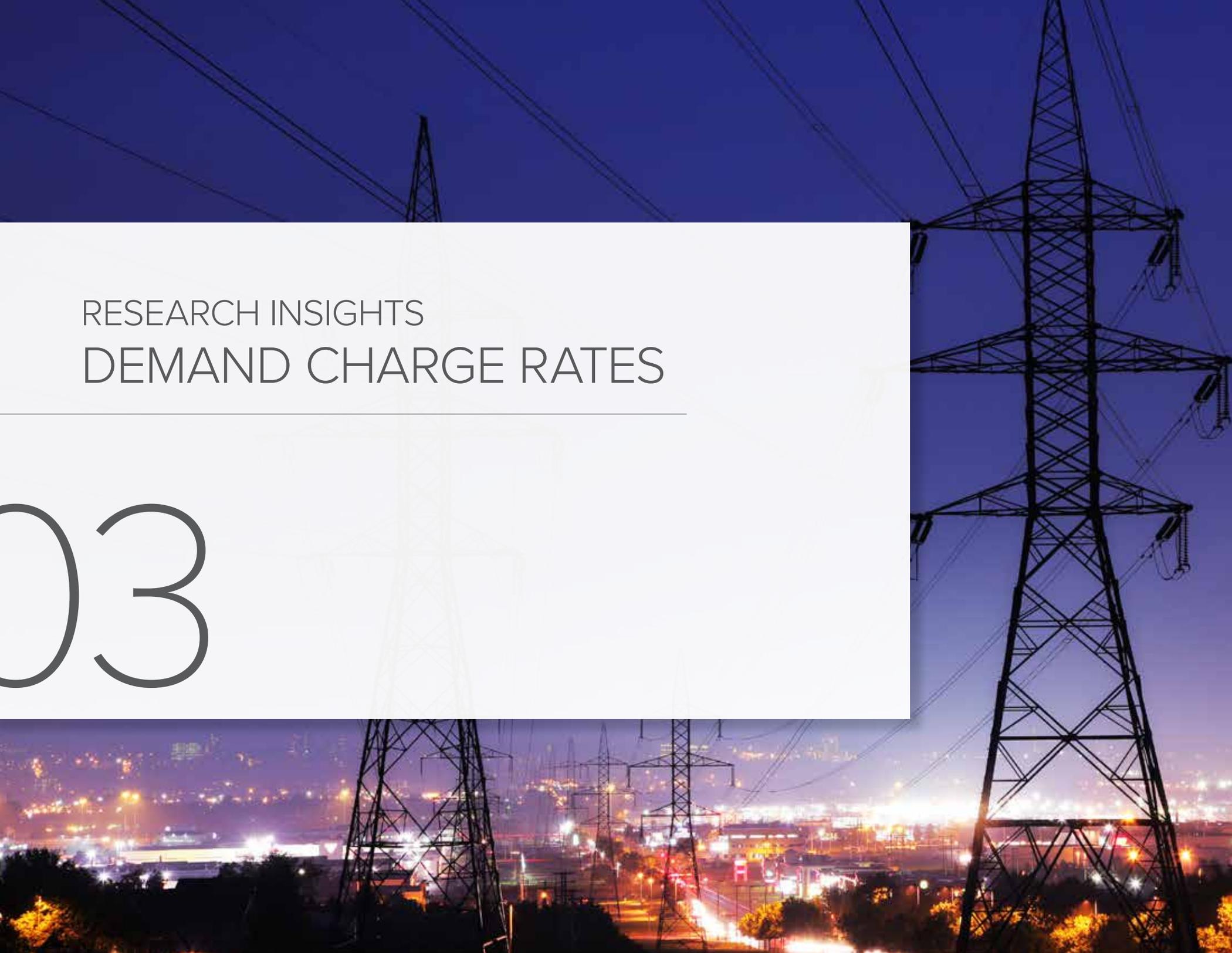
Time-based rates from SMUD and OG&E illustrate how good design principles can result in desired outcomes

- Because choices across the various dimensions are highly interrelated, it is critical to consider them holistically as well as individually. Ultimately, they will all have an effect on whether the rate achieves its objectives.
- OG&E's TOU rate (with variable peak and critical peak modifications) and SMUD's TOU rate are great examples of how this can be done in practice. Both rates balance customer needs and cost recovery by carefully considering design choices. For instance, both use a peak period duration and POPP ratio that enables customers to respond by changing their consumption patterns. Both OG&E and SMUD also included dedicated marketing and customer education campaigns.
- This thoughtful design resulted in two very successful rates, as indicated by the peak-reduction and customer-acceptance impacts shown at right. For example, SMUD's TOU rate achieved an average peak reduction of 6% despite being a default rate (and therefore including less-engaged customers, who are less responsive).

** The Cost Components & Allocation dimension is not included here, as the methodology used for each rate was not readily available.*

	SMUD SMART PRICING PILOT (BASIC TOU RATE)	OG&E SMART STUDY TOGETHER - (TOU WITH VP AND CP MODIFICATIONS)
DESIGN CHOICES*		
PEAK TO OFF-PEAK PRICE RATIO	1.1:1 (Winter) 2.6:1 (Summer)	TOU/VP: 2.5:1 to 10.2:1 Critical peak: 10.2:1
PEAK PERIOD DURATION	3 hours	TOU/VP: 5 hours Critical peak: 2–8 hours
PEAK PERIOD FREQUENCY	Weekdays	Capped at 120 hours/year for CP events
NUMBER OF PRICING PERIODS	2	Summer: 2 (+CP) Winter: 1 (+CP)
SEASONAL DIFFERENTIATION	2 seasons	2 seasons
FINANCIAL MECHANISM	Price-based	Price-based
ENROLLMENT METHOD	Default	Opt-In
ENABLING TECHNOLOGY	IHDs offered	PCTs offered
IMPACTS		
CUSTOMER PEAK-LOAD REDUCTION	6%	21%
REDUCTION IN ENERGY CONSUMPTION	No Data Available	No Data Available
CUSTOMER ACCEPTANCE	Enrollment: 98% Retention: 91%	Enrollment: 18% (of all residential customers) Retention: 97%

Source : [2, 10]



RESEARCH INSIGHTS
DEMAND CHARGE RATES

03

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

i. TYPES OF DEMAND CHARGE RATES

For clarity, this section provides a streamlined overview of the distinct types of demand charge rates.

ii. DIMENSIONS OF DEMAND CHARGE RATES

iii. KEY TAKEAWAYS

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

A limited number of mass-market demand charge rates are in place across the U.S., which vary in terms of age and design

ARIZONA

Salt River Power

SRP's unique, tiered demand charge rate increases with a customer's peak consumption, and was introduced in 2015 as mandatory for customers with distributed generation.

Arizona Public Service

One of the oldest demand charge rates, APS introduced the rate in 1981 as mandatory for customers with central air conditioning. The rate is currently offered on an opt-in basis, and has the highest enrollment (11%) of any residential demand charge rate nationwide.

SOUTH DAKOTA

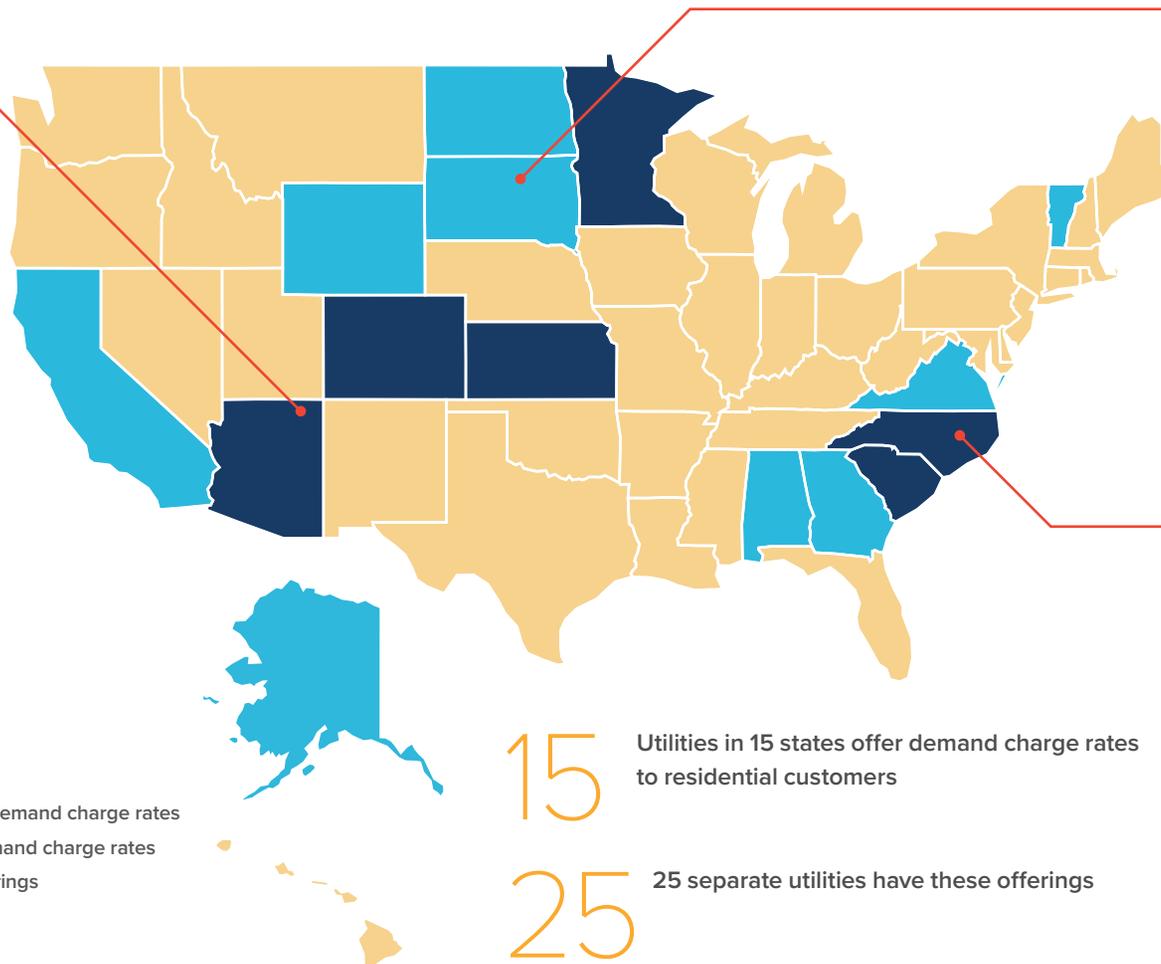
Black Hills Power

Black Hills Power's long-standing residential demand charge rate has one of the highest enrollment rates in the country at 8%. The rate is based on a customer's monthly noncoincident peak.

NORTH CAROLINA

Duke Energy

Approved in 2015, Duke's residential demand charge rate is one of the newest, and is based on a customer's *ex ante* coincident peak.



- More than one utility offers demand charge rates
- At least one utility offers demand charge rates
- No demand charge rate offerings

Data Sources: [5, 19]

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

There are two distinct types of demand charge structures, each with different implications for customers

TYPE	<i>EX POST</i>	<i>EX ANTE</i>
DESCRIPTION:	<ul style="list-style-type: none"> • Customers are charged based on peak demand in the previous billing period(s) • There is no cap on the customer’s peak demand 	<ul style="list-style-type: none"> • Customers choose a level of peak capacity prior to taking service, and are billed based on that level • Peak demand is capped at the selected service capacity—if they exceed that limit a customer’s service will trip off or their rate will increase
IMPLICATIONS:	<ul style="list-style-type: none"> • Well-designed <i>ex post</i> demand charges can provide a continuous price signal to customers to limit their peak consumption 	<ul style="list-style-type: none"> • <i>Ex ante</i> demand charges force customers to select a physical limit on peak consumption, but once that limit is selected they are effectively fixed
LOCATION(S) IMPLEMENTED:	<ul style="list-style-type: none"> • U.S., Australia 	<ul style="list-style-type: none"> • Spain, Italy, France, Indonesia
UTILITY EXAMPLES:	<ul style="list-style-type: none"> • Arizona Public Service—Demand-Based TOU • Black Hills Power (WY)—Residential Demand Service • Westar Energy (KS)—Restricted Peak Management Service 	<ul style="list-style-type: none"> • Électricité de France—Standard Tariff • Red Eléctrica de España—Standard Tariff

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

i. TYPES OF DEMAND CHARGE RATES

ii. DIMENSIONS OF DEMAND CHARGE RATES

This section outlines the major components of a demand charge rate and then presents detailed research on the potential options for each dimension and their implications

iii. KEY TAKEAWAYS

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

A demand charge rate requires choices along each of eight dimensions, some of which differ from time-based rates



PRICING FOUNDATION

1. **Cost Components & Allocation** What are the specific costs to be recovered through the rate, and what proportion of the costs are allocated to the demand charge?



STRUCTURE

1. **Peak Coincidence** Is the customer's peak demand measured at a specific time or period? (e.g., coincident with loading on the distribution or bulk system)
2. **Measurement Interval** What is the length of the period over which peak demand is measured?
3. **Number of Peaks** How many peak load measurements are included in the calculation of the customer's peak demand for a given billing period?
4. **Seasonal Differentiation** How many seasons (i.e., sets of months) have distinct rates?
5. **Ratchet Mechanism** Is the billed demand based on the maximum demand during the current billing period or does it consider past demand as well?



IMPLEMENTATION

1. **Enrollment Method** What strategy is used to enroll customers in the rate design program?
2. **Enabling Technology** What hardware and/or software is included to provide actionable information on consumption or prices, or to automatically control load in response to price signals?



PRICING FOUNDATION

#1: COST COMPONENTS & ALLOCATION

Certain cost components may be more appropriately recovered through a demand charge than through volumetric and customer charges

DEFINITION

The specific cost components to be recovered through a demand charge rate and the proportion of those costs allocated to the demand charge.

KEY TAKEAWAYS

- Selecting cost components recovered through a demand charge should be based on cost-causation, but there are three schools of thought on the appropriate way to do this:
 1. “Narrow” demand charges, which include only customer-specific equipment.
 2. “Broad” demand charges, which also include the customer’s share of all capacity-related distribution costs.
 3. “Extensive” demand charges, which also include production- and transmission capacity-related costs.
- Further industry research is needed to determine the impact of a demand charge’s magnitude on peak reduction and customer acceptance.



PRICING FOUNDATION

#1: COST COMPONENTS & ALLOCATION

In theory, the selection of cost components recovered through a demand charge can reflect cost-causation principles

OPTIONS

There are three schools of thought regarding the appropriate method for selecting cost components:

1. **Narrow Demand Charges** include only a customer's service drop and share of the line transformer.
2. **Broad Demand Charges** also include other capacity-related distribution costs.
3. **Extensive Demand Charges** include all costs associated with system infrastructure built to meet peak demand, including marginal generation and transmission capacity costs.

Proponents of narrow demand charges argue that these are the only components actually sized to meet the customer's individual peak demand. Meanwhile, other capacity-driven costs can be shared by all mass-market customers because, across the class, they have highly diverse load profiles. [22]

Proponents of broad and extensive demand charges argue that individual customers' demand directly contributes to system infrastructure requirements, and therefore those costs can be recovered through demand charges. [17]

RANGE OF FINDINGS

COST COMPONENTS	APPROACH		
	NARROW DEMAND CHARGE	BROAD DEMAND CHARGE	EXTENSIVE DEMAND CHARGE
Customer Meter*	X	X	X
Service Drop and Transformer	✓	✓	✓
Other Marginal Distribution- Capacity Costs	X	✓	✓
Marginal Transmission- Capacity Costs	X	X	✓
Marginal Generation- Capacity Costs	X	X	✓

* In some situations, a portion of AMI (and other smart-grid infrastructure) costs may be appropriately recovered through energy or demand charges. [22]

✓ Include X Exclude



PRICING FOUNDATION #1: COST COMPONENTS & ALLOCATION

In practice, existing mass-market demand charge rates show a variety of approaches to cost-component inclusion

	BURBANK WATER & POWER – BASIC SERVICE RATE	APS – TIME OF USE WITH DEMAND CHARGE	AUSTIN ENERGY – DEMAND CHARGE																																																								
TYPE:	<i>Ex ante</i>	<i>Ex post</i>	<i>Ex post</i>																																																								
CUSTOMER CLASS:	Residential	Residential	Small Commercial																																																								
COST COMPONENTS:	Includes <i>only</i> customer service drop and transformer [23]	Includes T&D and generation capacity	Includes T&D and generation capacity																																																								
RATE COMPONENTS:	“Service size charge” based on maximum possible demand [46]	Combines two-season TOU energy and demand charges	Includes delivery and demand charges																																																								
APPROACH:	<i>Narrow</i> Demand Charge	<i>Extensive</i> Demand Charge	<i>Extensive</i> Demand Charge																																																								
TARIFF DETAILS:	<table border="1"> <thead> <tr> <th>ELEMENT</th> <th>RATE</th> </tr> </thead> <tbody> <tr> <td>Customer Charge</td> <td>\$7.11 /month</td> </tr> <tr> <td>Service Size Charge</td> <td></td> </tr> <tr> <td>Small (e.g., multifamily)</td> <td>\$1.40 /meter</td> </tr> <tr> <td>Medium (e.g., single family)</td> <td>\$2.80 /meter</td> </tr> <tr> <td>Large (> 200 A panel)</td> <td>\$8.40 /meter</td> </tr> <tr> <td>Energy Charge</td> <td></td> </tr> <tr> <td>First 300 kWh</td> <td>\$0.12 /kWh</td> </tr> <tr> <td>Over 300 kWh</td> <td>\$0.17 /kWh</td> </tr> </tbody> </table>	ELEMENT	RATE	Customer Charge	\$7.11 /month	Service Size Charge		Small (e.g., multifamily)	\$1.40 /meter	Medium (e.g., single family)	\$2.80 /meter	Large (> 200 A panel)	\$8.40 /meter	Energy Charge		First 300 kWh	\$0.12 /kWh	Over 300 kWh	\$0.17 /kWh	<table border="1"> <thead> <tr> <th>ELEMENT</th> <th>RATE</th> </tr> </thead> <tbody> <tr> <td>Customer Charge</td> <td>\$ 0.58–0.77 /day depends on usage</td> </tr> <tr> <td>Demand Charge</td> <td></td> </tr> <tr> <td>Summer Peak (May–Oct, 12–7 pm)</td> <td>\$13.5 /kW</td> </tr> <tr> <td>Winter Peak (Nov–Apr, 12–7 pm)</td> <td>\$9.3 /kW</td> </tr> <tr> <td>Energy Charge</td> <td></td> </tr> <tr> <td>Summer Peak</td> <td>\$0.09 /kWh</td> </tr> <tr> <td>Summer Off-Peak</td> <td>\$0.04 /kWh</td> </tr> <tr> <td>Winter Peak</td> <td>\$0.06 /kWh</td> </tr> <tr> <td>Winter Off-Peak</td> <td>\$0.04 /kWh</td> </tr> </tbody> </table>	ELEMENT	RATE	Customer Charge	\$ 0.58–0.77 /day depends on usage	Demand Charge		Summer Peak (May–Oct, 12–7 pm)	\$13.5 /kW	Winter Peak (Nov–Apr, 12–7 pm)	\$9.3 /kW	Energy Charge		Summer Peak	\$0.09 /kWh	Summer Off-Peak	\$0.04 /kWh	Winter Peak	\$0.06 /kWh	Winter Off-Peak	\$0.04 /kWh	<table border="1"> <thead> <tr> <th>ELEMENT</th> <th>RATE</th> </tr> </thead> <tbody> <tr> <td>Customer Charge</td> <td>\$25 /month</td> </tr> <tr> <td>Delivery Charge</td> <td>\$4 /kW</td> </tr> <tr> <td>Demand Charge</td> <td></td> </tr> <tr> <td>Summer (Jun-Sep)</td> <td>\$6.15 /kW</td> </tr> <tr> <td>Winter (Oct-May)</td> <td>\$5.15 /kW</td> </tr> <tr> <td>Energy Charge</td> <td></td> </tr> <tr> <td>Summer</td> <td>\$0.029 /kWh</td> </tr> <tr> <td>Winter</td> <td>\$0.024 /kWh</td> </tr> </tbody> </table>	ELEMENT	RATE	Customer Charge	\$25 /month	Delivery Charge	\$4 /kW	Demand Charge		Summer (Jun-Sep)	\$6.15 /kW	Winter (Oct-May)	\$5.15 /kW	Energy Charge		Summer	\$0.029 /kWh	Winter	\$0.024 /kWh
ELEMENT	RATE																																																										
Customer Charge	\$7.11 /month																																																										
Service Size Charge																																																											
Small (e.g., multifamily)	\$1.40 /meter																																																										
Medium (e.g., single family)	\$2.80 /meter																																																										
Large (> 200 A panel)	\$8.40 /meter																																																										
Energy Charge																																																											
First 300 kWh	\$0.12 /kWh																																																										
Over 300 kWh	\$0.17 /kWh																																																										
ELEMENT	RATE																																																										
Customer Charge	\$ 0.58–0.77 /day depends on usage																																																										
Demand Charge																																																											
Summer Peak (May–Oct, 12–7 pm)	\$13.5 /kW																																																										
Winter Peak (Nov–Apr, 12–7 pm)	\$9.3 /kW																																																										
Energy Charge																																																											
Summer Peak	\$0.09 /kWh																																																										
Summer Off-Peak	\$0.04 /kWh																																																										
Winter Peak	\$0.06 /kWh																																																										
Winter Off-Peak	\$0.04 /kWh																																																										
ELEMENT	RATE																																																										
Customer Charge	\$25 /month																																																										
Delivery Charge	\$4 /kW																																																										
Demand Charge																																																											
Summer (Jun-Sep)	\$6.15 /kW																																																										
Winter (Oct-May)	\$5.15 /kW																																																										
Energy Charge																																																											
Summer	\$0.029 /kWh																																																										
Winter	\$0.024 /kWh																																																										



PRICING FOUNDATION

#1: COST COMPONENTS & ALLOCATION

Utility-specific analysis is required to understand the implications of each approach to selecting cost components

IMPORTANT CONSIDERATIONS

Selecting and allocating cost components for a demand charge can involve considering both cost drivers and the effectiveness of the recovery method:

- 1. Is the magnitude of the cost component driven by customer peak demand?** Costs driven by customer peak demand can include building, operating, and maintaining capacity (e.g., generation, transmission, and distribution), but many other costs are unrelated (e.g., energy, metering, customer connection, etc.).
- 2. Is the cost component best recovered through demand, volumetric, or customer charges?** Shifting variable and fixed costs into demand charges may help utilities hedge against uncertainty in volumetric sales but, to remain actionable for customers, demand charge rates can be restricted to peak capacity-driven costs (broad or extensive demand charges) and/or customer-specific capacity costs (narrow demand charges).

IMPACT ON OUTCOMES

Selection and allocation of cost components to a demand charge directly affects the magnitude of the charge (i.e., more costs result in a higher charge). This can impact customer response to the rate:

- **Peak Reduction:** Studies have not quantified customers' price elasticity of demand in response to demand charges. However, elasticity is expected to be negative, meaning that higher demand charges would yield higher customer peak reduction.
- **Customer Acceptance:** To date, no studies have evaluated the impact of demand charge magnitude on customer adoption or retention.



STRUCTURE

#1: PEAK COINCIDENCE

Most existing demand charge rates are based on the customer's noncoincident peak demand, but alternative options may better reflect cost causation

DEFINITION

The timing at which the customer's peak demand is measured to either coincide—or not coincide—with loading on the broader distribution or bulk system.

KEY TAKEAWAYS

- Noncoincident-peak demand charges are more straightforward for customers to understand and for utilities to administer but, if applied to anything beyond customer-specific costs, they may not reflect cost causation. [22]
- Modern metering technology enables coincident-peak demand charges, which more closely reflect cost causation because customers are billed according to their contribution to system loading during hours that drive capacity costs.
- Most of the 25 existing residential demand charge rates in the U.S. base charges on the customer's noncoincident peak (66%), while the rest base it on an *ex ante* coincident peak (33%). [19]
 - *Ex post* coincident-peak demand charges have been applied to large commercial and industrial customers, but haven't been used for mass-market customers.



STRUCTURE

#1: PEAK COINCIDENCE

There are a number of options beyond traditional noncoincident-peak demand charges that can be considered based on the specific costs being recovered

OPTIONS

Demand charges can be assessed based on the following: (see next page for an illustration of these options)

1. **Noncoincident peak**, which is the customer's maximum demand at any time during a billing period.
2. **Coincident peak**, which is the customer's peak demand at the time of the system peak. This option requires two additional decisions:

When is the timing of peak established?

- **Ex ante** coincident-peak demand charges are applied against the customer's demand during a predetermined peak period, which is selected to coincide with system peak. Existing coincident-peak residential demand charges use this option.
 - This option provides the customer information ahead of time about when the peak period will occur (i.e., they know exactly when to reduce their demand). For example, Salt River Project's residential demand charge has a specified peak period of 1–8 pm. [50]
- **Ex post** coincident-peak demand charges are applied against the customer's demand at the time when system peak actually occurs. This option is used in commercial and industrial demand charges (e.g., City of Fort Collins), but has not been used in residential rates.
 - With this option, the customer does not know ahead of time when the peak will occur (i.e., they don't know exactly when to reduce their demand).

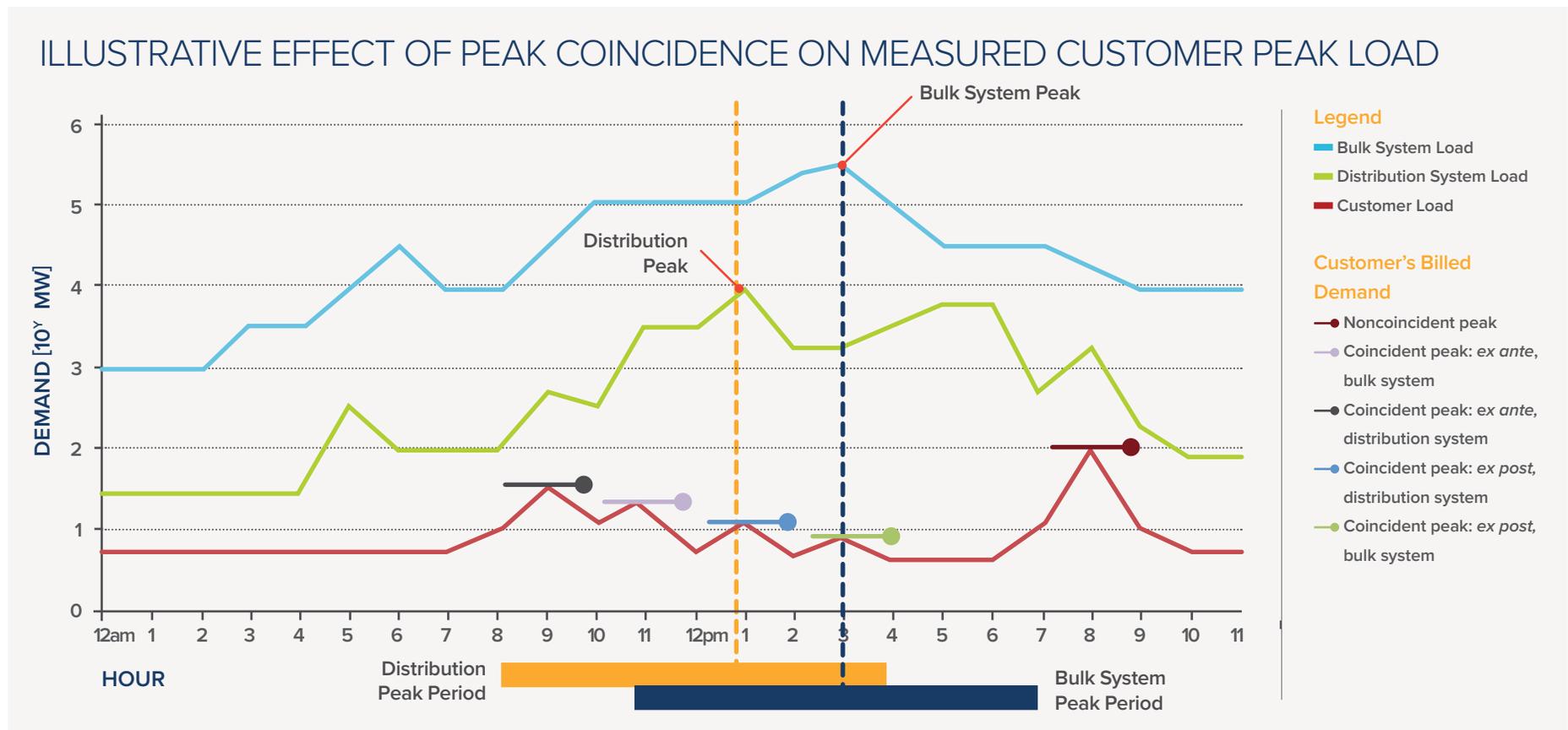
What level of the system determines the peak?

- **Distribution system**, which only includes loading on the portion of the utility's distribution system that is relevant to the customer (e.g., on the circuit or substation serving the customer).
- **Bulk system**, which includes loading on the utility's entire power system.



STRUCTURE #1: PEAK COINCIDENCE

For a given time period, a customer's billed demand can vary significantly, depending on which peak-coincidence option is used



03: RESEARCH INSIGHTS: DEMAND CHARGE RATES



STRUCTURE

#1: PEAK COINCIDENCE

There is limited evidence available about how coincident- and noncoincident-peak demand charges affect customer consumption or acceptance

IMPACT ON OUTCOMES

Customer Acceptance

- There have been no evaluations of how coincident-peak and noncoincident-peak demand charges impact customer enrollment or retention.

Peak Reduction

- There have been no evaluations that compare the impact of coincident-peak and noncoincident-peak demand charges on customer peak reduction.
- Only three studies have quantified peak reduction from a demand charge. Each tested a coincident-peak charge with long measurement intervals (6–8 hours), and peak reductions ranged from 5–41% across the studies. However, all had idiosyncrasies that limit the usefulness of their results: [17, 34]
 - Two of the studies, by Duke Power North Carolina and Wisconsin Public Service (WPS), are nearly 40 years old.
 - The only modern study is from Istad Nett AS in Norway, where the climate is significantly different than that in the vast majority of the U.S.
 - All three studies had very small sample sizes: WPS had just 40 participants, Duke only 178, and Istad, 443.
- Given the issues with these existing studies, no conclusions can be drawn until significantly more empirical evidence is available.



STRUCTURE

#2: MEASUREMENT INTERVAL

Behavior change from mass-market customers in response to a coincident peak demand charge may hinge on the measurement interval

DEFINITION

The length of the period over which peak demand is measured.

OPTIONS

Demand can be measured in one of two ways:

- **Instantaneously**, meaning the meter records actual power draw (or average energy at an interval short enough to be relatively instantaneous).
- **Averaged**, over the course of a given time period—typically 15 minutes, 30 minutes, or 60 minutes.
 - Instead of a single measurement, total consumption is recorded over the period and divided by the period length to find the average demand (illustrated in the figure on the next page).

KEY TAKEAWAYS

- Fundamentally, shorter measurement intervals and instantaneous measurement lead to higher—and more variable—measured peak demand (though this may not necessarily mean greater bill volatility).
- Measurement intervals of less than 60 minutes may not provide enough time for the typical mass-market customer to respond and adjust their demand to avoid peak load. [25]
- If the interval is too short for customers to respond, then the rate may effectively function as a fixed charge that varies month-to-month.
- All existing residential demand charge rates use an averaged demand interval of 15, 30, or 60 minutes—70% of noncoincident-peak rates use a 15-minute interval, while 75% of coincident-peak rates use a 30-minute interval. [19]

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

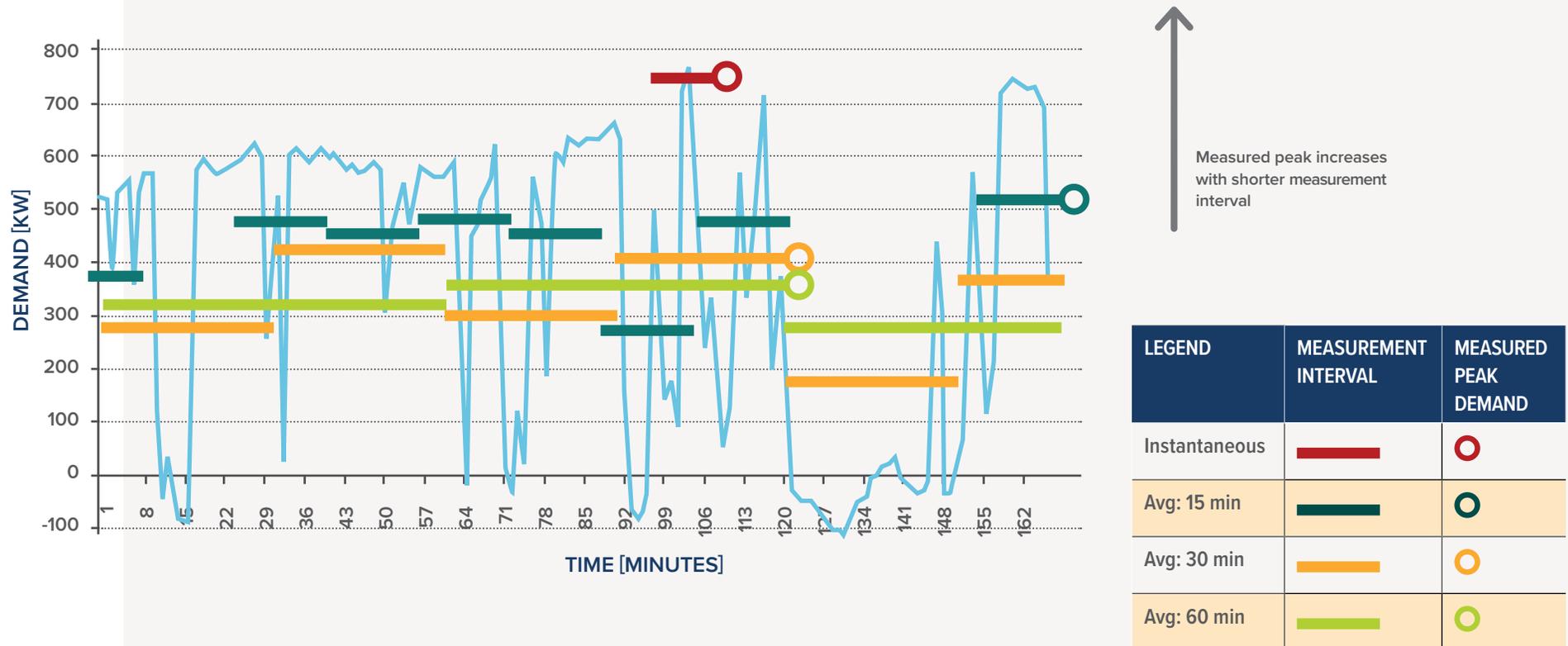


STRUCTURE

#2: MEASUREMENT INTERVAL

A longer measurement interval can be used to smooth the apparent load and reduce measured peak demand

ILLUSTRATIVE EFFECT OF DIFFERENT MEASUREMENT INTERVALS ON CUSTOMER PEAK LOAD



Example Load Data: Courtesy SDG&E



STRUCTURE

#2: MEASUREMENT INTERVAL

The measurement interval determines the level of load volatility that is captured, which directly influences bill volatility

IMPORTANT CONSIDERATIONS

- Shorter measurement intervals make it possible to capture spikes in customer demand:
 - A shorter measurement interval will always result in measured peak demand that is greater than or equal to measured demand under a longer interval.
- The acceptable level of bill volatility should be considered in selecting a measurement interval:
 - Individual mass-market customers typically have relatively low load factors and high load volatility, meaning that power spikes from a single appliance can significantly increase their peak demand under short measurement intervals. [25] However, as these customers are combined across a circuit, their total load factor may be relatively high, and their combined volatility relatively low.
 - In contrast, commercial and industrial customers typically have higher load factors and lower load volatility—as a result, instantaneous (or short-interval average) measurement may not result in significant bill volatility.

IMPACT ON OUTCOMES

Peak Reduction

There have been no evaluations of how a demand charge's measurement interval will impact customer peak reduction.

- However, if intervals are too short, customers may be unable to adjust their behavior quickly enough and may cease to respond to the price signal, making the demand charge effectively a fixed charge from the customer's perspective. [25]

Customer Acceptance

There have been no evaluations of how various measurement intervals impact customer enrollment or retention on demand charges.



STRUCTURE

#3: NUMBER OF PEAKS

Like measurement interval, calculating a demand charge using a larger number of peaks can mitigate large swings in a customer's measured peak demand

DEFINITION

The number of peak load measurements included in the calculation of the customer's peak demand for a given billing period.

OPTIONS

A customer's demand charge can be based on:

- **Single peak:** the highest peak demand measured in the period.
- **Multiple peaks:** the average of the two or more highest peaks in the period.

For example, a demand charge with a 60-minute measurement interval could average the five highest peak measurements from a given period (e.g., a month, a day, etc.). (See figure on the next page).

IMPACT ON OUTCOMES

- **Peak Reduction:** As with the measurement interval dimension, the number of peaks may influence customers' peak reductions, but no studies have evaluated this potential impact.

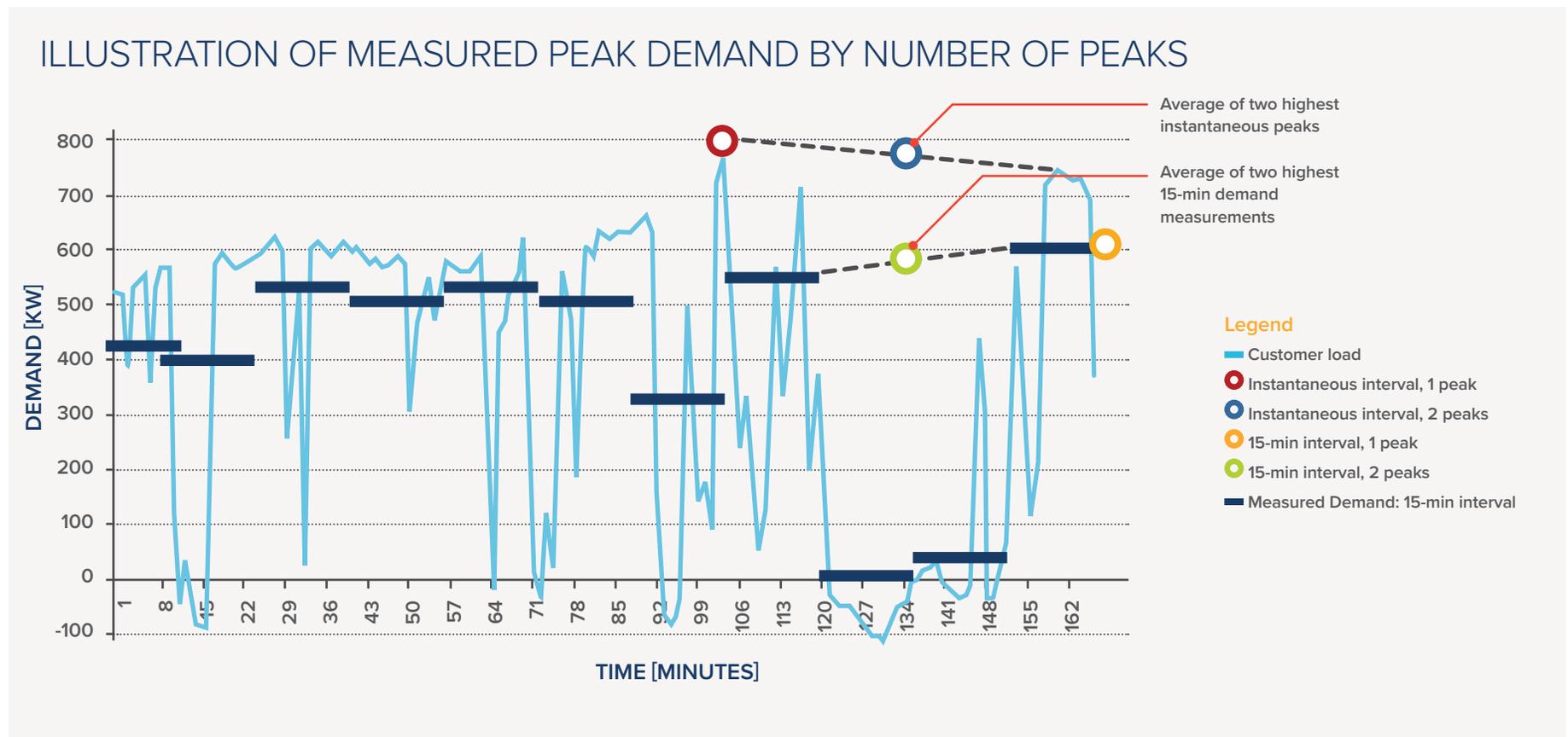
KEY TAKEAWAYS

- The single-peak method has been universally used in residential demand charges.
- The multiple-peaks method necessarily uses an average peak demand, which will never be greater than any single peak.



STRUCTURE #3: NUMBER OF PEAKS

As more measurements are incorporated into the peak-demand calculation, the measured peak is reduced



Example Load Data: Courtesy SDG&E



STRUCTURE

#4: SEASONAL DIFFERENTIATION

Rates with season-specific demand charges can better reflect cost causation in systems where loading varies significantly between times of the year

DEFINITION

The differentiation of prices by season (i.e., time of year) to recover costs that are specific to different times of the year.

OPTIONS

Demand charge programs may be:

- **Annual**, with the same rate across all seasons.
- **Bi-seasonal**, with distinct rates between two times of the year (e.g., winter/summer).
- **Multi-seasonal**, with distinct rates for three or more times of the year.
 - For example, Salt River Project's demand rate uses three periods: winter, summer, and summer peak (see table on the following page).

IMPACT ON OUTCOMES

- **Peak Reduction:** There have been no evaluations of how seasonal differentiation options can impact customer peak reduction.
 - Seasonal differentiation may enable greater peak reduction relative to annual demand charges, since the more concentrated peak-season rates send a stronger price signal to customers.

KEY TAKEAWAYS

- Seasonal differentiation allows costs to be concentrated into specific months of the year. This can enable more cost-reflective prices where loading and capacity-related costs vary significantly by time of year.
- The majority (60%) of existing residential demand charges utilize seasonal differentiation.
- Existing residential demand charges differentiate prices between seasons by as much as 3:1, though most do so by less than 2:1.

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES



STRUCTURE

#4: SEASONAL DIFFERENTIATION

Most existing residential demand charges differentiate between seasons, though only one rate uses more than two seasons

UTILITY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	RATIO OF CHARGES—HIGH VS. LOW SEASON	
Alabama Power						1.50							N/A	
Black Hills Power (SD)						8.10							N/A	
Black Hills Power (WY)						8.25							N/A	
City of Fort Collins (CO)						2.40							N/A	
City of Longmont (CO)						5.75							N/A	
City of Fort Morgan (CO)						10.22							N/A	
Georgia Power						6.53							N/A	
Midwest Energy (KS)						6.40							N/A	
Swanton Village Electric Department (VT)						6.38							N/A	
South Carolina Public Service Authority ¹						11.34 (On-peak); 4.85 (Off-peak)							N/A	
Alaska Power and Light		11.11					6.72					11.11	1.7 : 1	
Arizona Public Service		9.30				13.50					9.30		1.5 : 1	
City of Kingston (NC)		7.81					10.05					7.81		1.3 : 1
Duke Energy Carolinas (SC)		3.89				5.20					3.89		1.3 : 1	
Duke Energy Carolinas (NC)		3.88					7.77					3.88		2.0 : 1
Dominion North Carolina Power		5.00					8.55					5.00		1.7 : 1
Dominion Virginia Power		3.95					5.68					3.95		1.4 : 1
Otter Tail Power (MN)		5.11					6.08					5.11		1.2 : 1
Otter Tail Power (ND)		2.63					6.52					2.63		2.5 : 1
Otter Tail Power (SD)		5.93					7.05					5.93		1.2 : 1
Xcel Energy		6.59					8.57					6.59		1.3 : 1
Los Angeles Department of Water and Power		6.30					10.00					6.30		1.6 : 1
Westar Energy (KS)		3.00					10.00					3.00		3.3 : 1
Dakota Electric Association (MN)		9.30					12.90				9.30			1.4 : 1
Salt River Project (AZ)		3.41				8.03	9.59	8.03			3.41		2.8 : 1	

¹ The South Carolina Public Service Authority differentiates by time of day (peak/off-peak), but not by season.

Data Sources: [5, 19]



STRUCTURE

#5: RATCHET MECHANISM

Ratchet mechanisms are widely used in demand charges for large commercial and industrial customers to ensure cost recovery, but are currently used in few residential demand charge rates

DEFINITION

Whether billed demand is based on the maximum demand during the current billing period or is also based on historic demand.

KEY TAKEAWAYS

- Ratchet mechanisms are widely used in demand charge rates for large C&I customers, but adoption is limited in existing residential programs (5 out of 24 programs).
- Ratchet mechanisms need to be coordinated with cost allocation, especially because the high load diversity of residential customers may require different cost allocation strategies than C&I.
- No research has studied the impact of ratchet mechanisms on customer peak reduction but, theoretically, it may disincentivize customer response.



STRUCTURE

#5: RATCHET MECHANISM

Ratchet mechanisms can be implemented in a variety of ways

OPTIONS

1. **No ratchet**, where the billed demand is based on the maximum demand during the current billing period.
2. **Ratchet**, where billed demand is based on the maximum demand in the current month or past demand during a certain historic period. This option requires three additional decisions:

A. How many preceding months are included in the historic period?

- **Longer Period:** Most existing rates with a ratchet mechanism consider the past 11–12 months. For example, Otter Tail Power Company's Residential Demand Control Service Tariff includes the most recent 12 months. [39]
- **Shorter Period:** Some large C&I demand charges use a shorter period. For example, Pasadena Water & Power uses the most recent four months in their demand charges. [44]

B. Does the historic period include all months, or only certain months?

- **Specific Months:** The ratchet only considers peak demand in certain months (e.g., those in a summer or winter season). All other months do not affect the billing demand. Example rate: Midwest Energy. [48]
- **All Months:** Billed demand is based on the maximum during all preceding months. For example, Swanton Village Electric Department. [43]

C. What percentage of historic demand measurements is considered?

- **No Calculation:** The current month is compared against 100% of past demand measurements. For example, Otter Tail Power Company's demand charge rates. [39]
- **De-rated:** Demand in the current month is compared against less than 100% of demand in the historic period (typically 50–90%). For example, Midwest Energy compares against 80% of the peak in applicable past months. [48]

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES



STRUCTURE

#5: RATCHET MECHANISM

The various types of ratchet mechanisms can result in significantly different billed demand for customers

For an example customer under a demand charge rate, their billed demand in June 2015 depends on the ratchet mechanism used:

Baseline—No Ratchet

Billed Demand: Maximum demand during the current month

—Point A, 2.2 kW

Example #1—Seasonal Ratchet

Billed Demand: Maximum demand during the winter period (Sept–May) for the most recent 12 months

—Point B, 2.48 kW

Example #2—De-rated Seasonal Ratchet

Billed Demand: The greater of demand in the current month or 80% of the highest recorded demand during the most recent three summer-month billing periods (June–Aug)

—80% of Point C, 2.34 kW

Example #3—De-rated Longer-Period Ratchet

Billed Demand: The greater of the measured demand for the current month or 85% of the highest recorded demand during the preceding 11 months

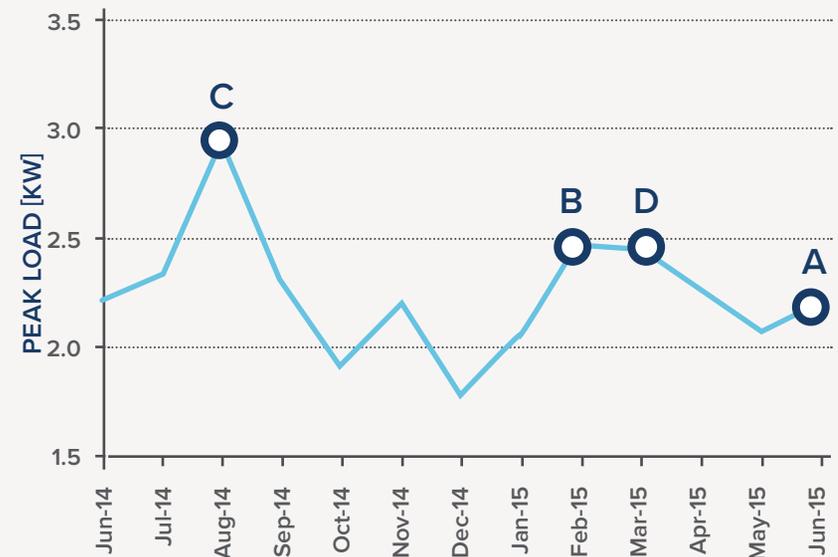
—85% of Point C, 2.49 kW

Example #4—Short-Period Ratchet

Billed Demand: Maximum demand from the four most recent months

—Point D, 2.45 kW

ILLUSTRATIVE MEASURED PEAK DEMAND FOR DIFFERENT RATCHET MECHANISMS





STRUCTURE

#5: RATCHET MECHANISM

Ratchet mechanisms are useful for stabilizing revenue recovery, but may disincentivize customer peak reduction

IMPORTANT CONSIDERATIONS

- Ratchet mechanisms have traditionally been used in C&I demand charges to help stabilize revenue from large customers who may have significant season-specific peaks but require system capacity to serve their peak load. The ratchet mechanism ensures cost recovery across all months.
- However, ratchet mechanisms may not be appropriate for residential demand charges, since system infrastructure is shared by a large number of residential customers whose combined load diversity results in a much higher load factor than individual large C&I customers. [22, 27]

IMPACT ON OUTCOMES

Peak Reduction

There has been no empirical research evaluating the impact of ratchet mechanisms on customer peak reduction.

- In theory, ratchet mechanisms may remove customers' incentive to reduce peak load under a demand charge, depending on how the ratchet is designed.
- For example, under a demand charge that ratchets up based on use in during a previous period (e.g., the three most recent summer months), customers won't have an incentive to reduce their peak demand in other months—their demand charge bill becomes fixed until the following summer. [22]
- However, if the ratchet is based on some number of preceding months (e.g., the four most recent months), then customers still have an incentive to limit their peak demand, since it will affect the ratchet for the next four months.



IMPLEMENTATION

#1: ENROLLMENT METHOD

Mass-market demand charge rates thus far have been mostly opt-in, but enrollment rates have been similar to those for time-based rates

DEFINITION

The strategy used to enroll customers in a rate.

OPTIONS

As with time-based rates, demand charges can be:

- **Mandatory**, where all customers must enroll.
- **Opt-out**, where customers are enrolled by default but have the option to switch to another rate.
- **Opt-in**, where customers can choose to participate, but otherwise are not enrolled.

IMPACT ON OUTCOMES

- **Customer Participation:** There have been no evaluations of how enrollment methods impact customer enrollment or retention on demand charges.
 - Existing opt-in residential demand charge rates have seen enrollment rates as high as 8–10% of customers (Black Hills Power and Arizona Public Service), but most programs are below 1%. [17]
 - Because opt-in enrollment rates for demand charge and time-based rates are similar, similar opt-out enrollment rates may be possible. [18]
- **Peak Reduction:** There have been no evaluations of differences in customer peak reduction between opt-in and opt-out demand charge rates.

KEY TAKEAWAYS

- Existing residential demand charge rates are opt-in (with a few programs mandatory for DG customers).
- Some existing small commercial demand charge rates are mandatory for customers of a certain size.
- For example, Austin Energy's small commercial demand charge is mandatory if the a customer's average summer peak demand is above 10 kW. [49]
- It's possible that opt-out mass-market demand charge rates could achieve enrollment rates similar to those seen for time-based rates.



IMPLEMENTATION

#2: ENABLING TECHNOLOGY

Enabling technologies may help customers better respond to demand charge price signals, but there is limited empirical evidence on the magnitude of their impact

DEFINITION

The hardware and software—provided with participation in a rate—that provide actionable information on consumption or prices, or automatically controls load in response to price signals.*

OPTIONS

- **Passive enabling technology** - includes in-home displays and other technologies that convey signals without taking action, e.g., actual price, price level, or other price indicator.
- **Active enabling technology** - includes devices that automatically, or through human intervention, modulate customer load in response to price or other signals.
 - For example, Black Hills Power offers a Demand Controller Program, which connects load-control devices to heating and cooling systems, hot water heaters, clothes dryers, and hot tubs to cycle these appliances on and off in 15-minute cycles to help residential customers manage demand charges. [13]

KEY TAKEAWAYS

- Active technologies have been used to regulate customer demand in response to a price signal by automatically adjusting energy consumption.
- The type of technologies that will be most useful to customers for reducing demand depends on whether demand is billed based on coincident peak or noncoincident peak.
- No research has studied the persistence of impacts from enabling technologies paired with demand charges.

* DER technologies, such as batteries, and utility-/aggregator-controlled dispatchable resources are not considered here.



IMPLEMENTATION

#2: ENABLING TECHNOLOGY

Both passive and active enabling technologies may help customers reduce peak demand, but require very different levels of customer engagement

IMPORTANT CONSIDERATIONS

- Passive technologies can alert customers when to adjust their demand in response to prices, while active technologies can receive price signals and automatically reduce a customer's peak load.
 - If customers are billed for noncoincident peak demand, active technologies can be used to continuously manage load to minimize peak at any time.
 - If billed for coincident peak demand, active technologies can be programmed to reduce demand during specific time periods.
- The architects of a study on a residential demand charge program in Norway reflected that customers would likely reduce peak demand further if they received:
 - Continuous information on their consumption level.
 - Frequent reminders about the type of tariff they are on.
 - Reminders about the time periods in which they incur the most cost for their demand. [34]

IMPACT ON OUTCOMES

Peak Reduction

There has been no empirical research evaluating the impact of enabling technologies.

- The most relevant study to date was conducted by The Brattle Group, which simulated customer response to a hypothetical demand charge and found that enabling technology could reduce customer demand by an additional 17% compared to the response without such technology. [18]

SIMULATED IMPACT OF A RESIDENTIAL DEMAND CHARGE ON CUSTOMER PEAK DEMAND, WITH AND WITHOUT ENABLING TECHNOLOGY

DEMAND MEASUREMENT	CHANGE WITHOUT ENABLING TECHNOLOGY	CHANGE WITH ENABLING TECHNOLOGY
Noncoincident Peak	-5.3%	-22%
Residential Class Peak	-1.7%	-3.1%
System Peak-Coincident	-1.5%	-3%

Data Source: [18]

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

i. TYPES OF DEMAND CHARGE RATES

ii. DIMENSIONS OF DEMAND CHARGE RATE

iii. KEY TAKEAWAYS

This section provides an overview of the findings from this research, and discusses the most important implications for continued consideration of demand charge rates

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

KEY TAKEAWAYS

Well-designed demand charge rates may result in beneficial outcomes, but there is limited empirical evidence and most arguments remain speculative

- Our review found there is still little industry experience with mass-market demand charges relative to other rate designs. Minimal empirical evidence is currently available to provide insight on the efficacy or impact of demand charge rates on any desired outcomes beyond cost recovery. However, there is lively debate about how they may affect key desired outcomes, including customers' peak consumption, total energy consumption, and acceptance (in terms of enrollment and retention). While claims regarding the potential impact of demand charge rates on these outcomes (positive or negative) are largely speculative, there is a clear need for the industry to align on what is currently known and unknown, and on what further research will be most useful.
- While there is a clear gap in the empirical evidence on the impact of demand charges, our research suggests that there are key design choices that will determine the efficacy of the rate. Of the eight important design dimensions for demand charge rates, four are likely to be particularly influential: *Cost Components & Allocation* directly determines the magnitude of the demand charge price, while customers' ability to respond to the rate is likely to be strongly affected by *Peak Coincidence*, *Ratchet Mechanism*, and *Enabling Technology*.

RANGE OF FINDINGS

DESIRED OUTCOME	AVAILABILITY OF EMPIRICAL EVIDENCE	POTENTIAL IMPACT
Reduction in Total Energy Consumption	There is insufficient reliable evidence indicating the potential impacts of demand charges on total consumption.	Unclear
Customer Peak Load Reduction	While it's possible that, if customers are sufficiently educated about a demand charge rate, they will reduce peak demand in response, no reliable studies have evaluated the potential for peak reduction as a result of demand charges.	Unclear
Customer Acceptance	This can be evaluated in terms of enrollment rates and retention rates. While existing opt-in residential demand charges offer a glimpse into potential enrollment, no studies have considered retention rates.	Enrollment: 1–10% Retention: Unclear

** Demand charge rates have a long history of application with large commercial and industrial (C&I) customers; however, the impact of demand charges on those customers cannot be extrapolated to the mass-market sector, as the behavior and decision-making processes of C&I customers are significantly different (for example, over half of C&I customers employ a dedicated energy manager). [12]*

03: RESEARCH INSIGHTS: DEMAND CHARGE RATES

KEY TAKEAWAYS

Existing demand charge rates from APS and Black Hills Power illustrate how different demand charges can be in practice

- Very little empirical evidence is available to compare the impact of how the various demand charge-rate design choices combine to affect outcomes such as customer peak reduction or reduction in total energy consumption.
- However, APS and Black Hills Power offer demand charge rates that are very different in design, but have achieved relatively high enrollment compared to other demand charge rates in the U.S. Extensive customer education and offering load-control technology has contributed to these high enrollment rates, as do the rates' long histories (both rates have been in place for more than three decades) and the APS rate's initial implementation as a mandatory rate for some customers.
- Of the two, the APS rate's coincident-peak design is likely to better reflect cost causation, while the one-hour measurement interval may provide customers a better opportunity to adjust consumption to avoid spikes in demand.

** The Cost Components & Allocation dimension is not included here, as the methodology used for each rate was not readily available.*

	ARIZONA PUBLIC SERVICE	BLACK HILLS POWER (SD)
DESIGN CHOICES*		
PEAK COINCIDENCE	<i>Ex ante</i> Coincident	Noncoincident
MEASUREMENT INTERVAL	1 hour during 7 coincident peak hours	15 minutes
NUMBER OF PEAKS	Single measurement	Single measurement
SEASONAL DIFFERENTIATION	2 seasons	1 season
RATCHET MECHANISM	None	None
ENROLLMENT METHOD	Opt-in	Opt-In
ENABLING TECHNOLOGY	Load control technology marketed	"Demand controllers" offered
IMPACTS		
AVERAGE PEAK REDUCTION	No Data Available	No Data Available
REDUCTION IN ENERGY CONSUMPTION	No Data Available	No Data Available
CUSTOMER ENROLLMENT	11%	8%

Data Source : [17]

A close-up photograph of a hand holding a white paper cup. The background is a bright, sunlit field of tall grasses, creating a warm, golden glow. The hand is positioned on the right side of the frame, with the thumb and index finger gripping the rim of the cup. The cup is tilted slightly, and the liquid inside is not clearly visible. The overall mood is serene and natural.

CONCLUSIONS

04

04: CONCLUSION

RESEARCH TAKEAWAYS

Specific design choices are key to the efficacy of any time-based or demand charge rate.

- While all of the design dimensions outlined in this report are important to consider, the most critical choices for time-based rates include the financial mechanism, the ratio of peak to off-peak prices, and whether the rate includes a modification mechanism (e.g., critical peak or variable peak) to add sophistication. These choices are key to determining whether the rate accurately reflects time-varying system costs, and whether the rate will enable customer response.
- For demand charge rates, how cost components are allocated and whether prices are coincident with peak will determine whether or not the rate sends accurate price signals to customers about system costs. Meanwhile, other structural dimensions influence whether the rate enables customer response—specifically, the measurement of demand (both interval and frequency) and whether there is a ratchet mechanism.

Empirical evidence is available for time-based rates, but is limited for demand charge rates.

- A significant amount of research is available on the effects of time-based rates, and there is clear insight on best-practice design choices. This research consistently indicates that well-designed time-based rates are effective at achieving their objective of providing a price signal to customers about when to use energy (and when not to). This has compelled several regions—including California, Massachusetts, and the province of Ontario—to transition toward default TOU rates for all residential customers. [15, 42, 47]
- In contrast, there is limited empirical evidence on the efficacy or impacts of mass-market demand charges on any desired outcome beyond cost recovery. It remains unclear whether demand charge rates effectively communicate price signals to customers about how to change their usage to reduce system cost.

In theory it may be possible to achieve similar objectives using time-based and demand charge rates, but this remains unproven in practice.

- Proposals often state similar objectives, including recovering costs while sending price signals that better reflect the drivers of those costs, which can lead customers to change their consumption in a way that helps the system. However, it is unclear whether the two rate designs send equally effective price signals—more evidence on the impacts of demand charges is needed.

04: CONCLUSION

RESEARCH TAKEAWAYS

States, regulators, and utilities considering these alternative rates should incorporate identified best-practice design principles.

- Using design choices described in this report, effective time-based rates can be developed and widely deployed, for example, through default or opt-out rate offerings, or improved opt-in programs. In locations where time-based rates have not previously been implemented, demonstration projects using a robust experimental design can help quickly gain market experience.*
- The eventual path for development of demand charge rates could be similar to that recommended for time-based rates, but more experience with the impacts of mass-market demand charges should be gained using demonstration and evaluation projects before wider rollout is considered. While demand charges may provide for utility cost recovery, their impacts on other rate design principles—particularly those relating to fairness and customer experience and response—remains unclear.
- For any rate design to be most effective, it needs to be coupled with robust customer education, engagement, and marketing campaigns, and should explicitly consider how to increase adoption of enabling technology.

Rate design needs to achieve more than just cost recovery, including support for policy objectives.

- In response to concerns about stagnating load growth and DER adoption, new utility rate proposals often focus on cost recovery at the expense of achieving other recognized objectives and established rate-design principles. While cost recovery remains an important objective, it can be achieved in balance with other objectives.

Improved mass-market rates for consumption are necessary, but not sufficient.

- New approaches—including time-based and demand charge rates—are critical for near-term progress toward better pricing that reflects system costs and fulfills societal needs. But ongoing attention is also needed to develop more-sophisticated pricing structures and compensation mechanisms that fairly represent the benefits and costs of distributed energy resources, as well as customers' use of the system.

* *The approaches used by utilities in the U.S. Department of Energy's Consumer Behavior Studies program provide an excellent blueprint to follow. [52]*

04: CONCLUSION

RESEARCH TAKEAWAYS

Going forward, there are significant knowledge gaps related to both time-based and demand charge rates that the industry and researchers should address. Specific topics that emerged through this work include:

Evaluate rate impacts on total energy consumption

- The majority of studies that have considered customers' behavioral response to alternative rates have evaluated the impacts on customer peak reduction, but very few evaluated the impacts on total energy consumption. Regardless of whether the intent of a time-based or demand charge rate is to impact total energy consumption, this is a critical consideration and the rate's effect is important to understand.

Identify the impact of demand charges on key outcomes

- As noted throughout this report, the literature offers little empirical evidence of the impact of mass-market demand charges on important outcomes, such as customer peak load reduction and customer acceptance. These impacts need to be evaluated and published in order for regulators and utilities to make informed decisions about whether or not demand charges should be adopted.

Understand the impact of combining time-based and demand charge rates

- There may be opportunities for rates that combine time-based energy prices with a demand charge. Such rates have not been evaluated in the literature to date, but could be explored to learn whether there are benefits from coupling the two approaches.

Improve understanding of the relationship of rates and technology

- There is a growing body of work that considers how enabling technology may affect the impact of alternative rates. Going forward, additional research should continue to evaluate new technology (or new capabilities from existing technology) to identify the most promising options. Research should also consider whether alternative rates incentivize customer adoption of that technology and what design choices could increase the benefits of technology to both customers and the system.

Clarify methods for including and allocating cost components

- Cost classification and allocation methods are well known in the context of traditional rate designs, but there is limited transparency into approaches used in time-based and demand charges rates. In particular, utilities, regulators, and researchers should be transparent about which cost components are included in a demand charge and in how those are allocated between each time period of a time-based rate.

BIBLIOGRAPHY

05



05: BIBLIOGRAPHY

- [1] C. Armel, D. Sullivan, and A. Todd, “When ‘Not Losing’ is Better Than ‘Winning:’ Using Behavioral Science to Drive Customer Investment in Energy Efficiency.”
- [2] M. Badtke-Berkow, M. Centore, K. Mohlin, and B. Spiller, “A Primer on Time-Variant Electricity Pricing,” Environmental Defense Fund, 2015.
- [3] Baltimore Gas & Electric, “BGE Peak Rewards,” *Baltimore Gas and Electric Company*. [Online]. Available: <http://bgesavings.com/earthday>. [Accessed: 15-Jan-2016].
- [4] L. Bird, J. McLaren, J. Heeter, C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostrander, “Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar,” National Renewable Energy Laboratory, 2013.
- [5] L. Bird, J. McLaren, J. Miller, and C. Davidson, “Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates,” National Renewable Energy Laboratory, Golden, CO, TP-6A20-64850, Sep. 2015.
- [6] J. C. Bonbright, A. L. Danielsen, and D. R. Kamerschen, *Principles of Public Utility Rates*. Public Utilities Reports, Incorporated, 1988.
- [7] S. Borenstein, “Effective and Equitable Adoption of Opt-in Residential Dynamic Electricity Pricing,” *Review of Industrial Organization*, vol. 42, no. 2, pp. 127–160, 2013.
- [8] S. Borenstein, “Peak-Time Rebates: Money for Nothing,” *Greentech Media*, 12-May-2014.
- [9] T. Brown and A. Faruqi, “Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs,” The Brattle Group, 2014.
- [10] P. Cappers, L. Hans, and R. Scheer, “Customer Response To Time Based Rates,” Lawrence Berkeley National Laboratory, LBNL-183029, Jun. 2015.
- [11] N. Darghouth, “Uncertainties in the Value of Bill Savings from Behind-the-Meter, Residential Photovoltaic Systems: The Roles of Electricity Market Conditions, Retail Rate Design, and Net Metering,” University of California, Berkeley, 2013.
- [12] J. Davies, “State of the Profession—2013,” GreenBiz Group, Jan. 2013.

05: BIBLIOGRAPHY

- [13] M. Dyson, “How Demand Flexibility Can Help Rooftop Solar Beat Demand Charges in Arizona,” *RMI Outlet*, 14-Sep-2015.
- [14] Energy Information Administration, “Annual Electric Power Industry Report (EIA-861 data file),” 2014.
- [15] A. Faruqui, R. Hledik, and N. Lessem, “Smart by Default,” *Public Utilities Fortnightly*, Aug. 2014.
- [16] A. Faruqui and S. Sergici, “Arcturus: International Evidence on Dynamic Pricing,” *The Electricity Journal*, vol. 26, no. 7, pp. 55–65, Aug. 2013.
- [17] R. Hledik, “Rediscovering Residential Demand Charges,” *The Electricity Journal*, vol. 27, no. 7, pp. 82–96, Aug. 2014.
- [18] R. Hledik, “Rolling Out Residential Demand Charges,” presented at the EUCI Residential Demand Charges Summit, Denver, CO, May-2015.
- [19] R. Hledik, “The Top 10 Questions about Demand Charges,” presented at the EUCI Residential Demand Charges Summit, Denver, CO, May-2015.
- [20] K. Ito, T. Ida, and M. Tanaka, “The Persistence of Intrinsic and Extrinsic Motivation: Experimental Evidence from Energy Demand,” Working Paper, 2014.
- [21] K. Jessoe, D. Rapson, and J. B. Smith, “The Effect of a Mandatory Time-of-Use Pricing Reform on Residential Electricity Use,” Nov. 2012.
- [22] J. Lazar and W. Gonzalez, “Smart Rate Design for a Smart Future,” Regulatory Assistance Project, Jul. 2015.
- [23] J. Lazar and S. Swe, “Demand Charges: Pathway or Detour?,” presented at the RAP Webinar, 10-Dec-2015.
- [24] J. Lazar, “Cost Elements and Study Organization For Embedded Cost of Service Analysis,” Regulatory Assistance Project, Jul. 1992.
- [25] C. Linvill, J. Shenot, and J. Lazar, “Designing Distributed Generation Tariffs Well,” *Montpelier, VT: Regulatory Assistance Project*, 2013.

05: BIBLIOGRAPHY

- [26] G. Mandelman, “Adjusting TOU Rates Today For California’s Grid of Tomorrow - How and Why PG&E is Modifying its Residential TOU Periods and Pricing to Reflect Growing Solar & Wind Integration,” presented at the 2015 National Town Meeting, Washington, D.C., 28-May-2015.
- [27] C. Murray, “Texas Small Businesses May Get ‘Demand Ratchet’ Relief,” *SaveOnEnergy*, 05-Apr-2012.
- [28] R. Passey, M. Watt, and N. Morris, “A Distributed Energy Market: Consumer & Utility Interest, and the Regulatory Requirements,” The Australian PV Association, Aug. 2013.
- [29] J. M. Potter, S. S. George, and L. R. Jimenez, “SmartPricing Options Final Evaluation,” Sacramento Municipal Utility District, Sacramento, CA, Sep. 2014.
- [30] S. Price and J. Williams, “A Survey of Time-Of-Use Pricing and Demand Response Programs,” *Energy and Environmental Economics*, Nov. 2015.
- [31] S. Schare, “TOU Rates As If Prices Mattered: Reviving an Industry Standard for Today’s Utility Environment,” American Council for an Energy-Efficient Economy, 5-281, Jan. 2008.
- [32] O. Smith, M. Lehrman, and D. Glick, “Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future,” Rocky Mountain Institute, Aug. 2014.
- [33] State of New York - Department of Public Service, “Staff White Paper on Ratemaking and Utility Business Models,” Jul. 2015.
- [34] A. Stokke, T. Ericson, and G. L. Doorman, “An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector.” Statistics Norway, Jan. 2009.
- [35] Troutman Sanders LLP, “FERC Settles Investigation Concerning Demand Response Products in PJM,” *Washington Energy Report*, Jun. 2013.
- [36] R. Walton, “SMUD: Time-of-Use is the Future of Rate Design,” *Utility Dive*, 13-May-2015.
- [37] R. Walton, “‘Game-ifying’ Demand Response: How One Utility Tries to Keep DR Programs Fresh for Customers,” *Utility Dive*, 09-Mar-2016.
- [38] M. Whited, T. Woolf, and J. Daniel, “Caught in a Fix: The Problem with Fixed Charges for Electricity,” Synapse Energy Economics, Cambridge, MA, Feb. 2016.
- [39] “Otter Tail Power Company Residential Demand Control Service Tariff,” Otter Tail Power Company, 01-Oct-2011.

05: BIBLIOGRAPHY

- [40] "Electric Service Rates in the State of Wisconsin." Wisconsin Electric Power Company, 21-Dec-2012.
- [41] "Analysis of Customer Enrollment Patterns in Time-Based Rate Programs - Initial Results from SGIG Customer Behavior Studies," Department of Energy EE&RE, Jul. 2013.
- [42] "Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid." Massachusetts Department of Public Utilities, 12-Jun-2014.
- [43] "Swanton Village Electric Department Residential Demand Service Schedule," Swanton Village Electric Department, 01-Sep-2014.
- [44] "City of Pasadena Frequently Asked Questions Distribution Charge & Demand Billing," Pasadena Water & Power, 15-Apr-2015.
- [45] "Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies (CBS)," U.S. Department of Energy EE&RE, Jun. 2015.
- [46] "City of Burbank: Adopted Citywide Fee Schedule." City of Burbank, 02-Jun-2015.
- [47] "Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates." California Public Utilities Commission, 03-Jul-2015.
- [48] "Midwest Energy Residential Demand Rate Service Tariff," Midwest Energy, 19-Oct-2015.
- [49] "City of Austin - Electric Tariff." Austin Energy, 01-Nov-2015.
- [50] "Residential Demand Price Plan for SRP Residential Electric Customers." [Online]. Available: <http://www.srpnet.com/prices/home/residentialdemand.aspx>. [Accessed: 21-Jan-2016].
- [51] "Simple Energy - Energy Rewards." [Online]. Available: <http://simpleenergy.com/product/energy-rewards/>. [Accessed: 05-Jan-2016].
- [52] "Approach to Consumer Behavior Studies - DOE's Smart Grid Investment Grant Consumer Behavior Studies," U.S. Department of Energy, Oct. 2011.

