Division 2-19

Request:

Refer to Appendix 4.1, Table 4-12: Assumptions to estimate savings from time varying rates:

a. Please provide the price ratio for CPP assumed when estimating the expected CPP peak load reduction.

b. Please confirm that the CPP Peak Load Reduction and the TOU On-Peak Energy Reduction values are average per-customer values for residential customers.

c. Please provide the average peak load (kW) for a residential customer for each of the past 5 years.

d. Please explain why the peak load reduction assumptions for opt-in rates are reasonable.

e. Please explain why the peak load reduction assumptions for opt-out rates are reasonable.

f. Please identify whether the CPP Peak Load Reduction assumptions are incremental to the peak load reductions achieved from TOU.

g. Please provide the full text of source: The Brattle Group Economists (Submitted to EDI Quarterly), The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity, March 2012.

h. Please describe how the estimated 20% opt-in rate was developed, including the specific sources relied upon.

i. Please provide the expected annual number of days in which critical peak pricing events would be called.

j. Please provide the expected duration of each critical peak pricing event.

Response:

a. The Company's analysis did not assume a specific critical peak pricing (CPP) price ratio. However, as discussed in parts d. and e. of this response, the assumptions on customer response were informed by both National Grid's experience with its Smart Energy Solutions Pilot in Worcester, Massachusetts, as well as literature on customer response under CPP. In the absence of a specific rate design, the Company has evaluated both low and high customer response levels to provide a reasonable range of estimated customer savings due to peak reductions.

b. The CPP Peak Load Reduction and TOU On-Peak Energy Reduction values represent average per-customer values for participating residential customers.

c. The table below provides the average residential customer peak load in (kW) for years 2012-2016.

Average Residential Customer Peak Load (kW) from 2012-2016

Year	Avg. Peak (kW)
2012	2.06
2013	2.12
2014	1.90
2015	1.89
2016	2.17

d. The Company assumed both low (8 percent) and high (18 percent) peak load reduction assumptions for an opt-in rate to ensure a reasonable estimated range of savings. These chosen values are well within the range of observed values for CPP programs. Research by the Brattle Group, provided as Attachment DIV 2-19-1, has identified peak reductions ranging from about 6 percent to over 60 percent in their review of existing CPP programs. Second, Department of Energy’s (DOE) recent analysis, provided as Attachment DIV 2-19-2, of time-varying rate programs implemented by utilities participating in the Consumer Behavior Studies (CBS) under the Smart Grid Investment Grants Program found an average peak reduction of 23 percent under opt-in CPP programs.

Finally, National Grid’s Smart Energy Solutions Pilot in Worcester, Massachusetts, achieved over an 18 percent peak reduction in its second year for the customer segments that were most engaged and could reasonably be assumed to be representative of opt-in customers. The CPP peak to off-peak ratio in the pilot was just below 6.0 to 1.

e. The Company’s assumed both low (6 percent) and high (13.5 percent) peak load reduction assumptions for an opt-out rate in order to ensure a reasonable estimated range of savings. Because the average customer under an opt-out program is likely to be less engaged than a customer who has opted in, the Company has assumed that average peak load reductions are 25 percent less under the opt-out scenario than the opt-in scenario. DOE’s report provided as Attachment DIV 2-19-2, found an average of 13 percent peak reduction under opt-out CPP programs at the CBS utilities. National Grid’s Smart

Energy Solutions Pilot, which features an opt-out CPP design, achieved peak reductions of 7 percent overall in the second year of the program. The Company expects that peak reductions under a broader, long-term (e.g., 20 years) would exceed those experienced under a pilot.

f. To avoid the potential for double-counting, the Company did not attribute any peak reduction to the time of use (TOU) rate alone. The Company attributed energy savings to the TOU rate, and peak reduction to the CPP rate.

g. Please see Attachment DIV 2-19-1 for the requested information.

h. The 20 percent opt-in assumption was selected by the Company based on a review of recent studies of customer participation rates in opt-in time-varying rates. DOE's review of time-varying rate programs at the CBS utilities, provided as Attachment DIV 2-19-2, found an average opt-in rate of 15 percent and a range of less than 5 percent to almost 40 percent. Based on an analysis of participation rates in time-varying pricing programs conducted for Portland General Electric, The Brattle Group, and Applied Energy Group have proposed "steady state" enrollment rate assumptions, provided as Attachment DIV 2-19-3, for residential CPP programs of 17 percent when enabling technology is not provided and 22 percent when such technology is provided. The Company believes that at 20 percent steady state opt-in rate is reasonable given that the Company would expect any opt-in program to be paired with aggressive outreach and education, as well as the enablement of customer access to supporting information and technologies that support customer response. The Brattle Group notes that Oklahoma Gas & Electric has achieved a target 20 percent participation rate in its variable peak pricing (VPP) program, which includes a CPP component, a year ahead of schedule.

i. and j. The Company is not proposing a specific CPP design at this point. However, the Company expects that an eventual proposal would be informed by National Grid's experience with the Smart Energy Solutions pilot. Under that program, the Company is permitted to call up to 30 CPP events (called conservation days in the program) with a maximum duration of 8 hours. In both 2015 and 2016, the Company called 20 CPP events with an average length of 6.75 hours in 2015, and 6.95 hours in 2016. Design must ultimately balance the need for the Company to call a sufficient number of events and for a sufficient duration to enable meaningful demand reductions that provide customer savings, with the need to maintain customer satisfaction by ensuring the events are not called too frequently and that their duration is not such that customers do not have a meaningful opportunity to shift their energy demand.

(This response is identical to the Company's response to Division 8-19 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Submitted to the EDI Quarterly

The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity

Ahmad Faruqui and Jenny Palmer[1]

Abstract

This paper surveys the results from 126 pricing experiments with dynamic pricing and time-of-use pricing of electricity. These experiments have been carried out across three continents at various times during the past decade. Data from 74 of these experiments are sufficiently complete to allow us to identify the relationship between the strength of the peak to off-peak price ratio and the associated reduction in peak demand or demand response. An "arc of price responsiveness" emerges from our analysis, showing that the amount of demand response rises with the price ratio but at a decreasing rate. We also find that about half of the variation in demand response can be explained by variations in the price ratio. This is a remarkable result, since the experiments vary in many other respects – climate, time period, the length of the peak period, the history of pricing innovation in each area, and the manner in which the dynamic pricing designs were marketed to customers. We also find that enabling technologies such as in-home displays, energy orbs and programmable and communicating thermostats boost the amount of demand response. The results of the paper support the case for widespread rollout of dynamic pricing and time-of-use pricing.

Introduction

Electric utilities, which run a capital-intensive business, could lower their costs of doing business by improving their load factor. Other capital intensive industries, such as airlines, hotels, car rental agencies, sporting arenas, movie theaters routinely practice a technique known as dynamic pricing to improve load factor. In dynamic pricing, prices vary to reflect the changing balance of demand and supply through the day, through the week and through the seasons of the year.

Congestion pricing, a simpler form of dynamic pricing, is used to regulate the flow of cars into central cities. Parking spaces in most central cities are priced on a time-of-day basis and in some cities such as San Francisco the prices are varying dynamically. In California, special lanes on freeways are priced dynamically and the Bay Bridge charges toll on a time-of-use basis.

But it has been difficult for electric utilities to follow these examples. There has always been doubt that electric users can change their usage patterns. To assuage these doubts, in the late 1970s and early 1980s, a dozen electricity pricing experiments were carried out with time-of-use rates in the United

[1] The authors are economists with The Brattle Group, based in San Francisco. They are grateful to fellow economist Sanem Sergici of Brattle for reading an early draft of this paper. Comments can be directed to ahmad.faruqui@brattle.com.

States.[2] They showed that customers do respond to such rates by lowering peak usage and/or shifting it to less expensive off-peak periods. But smart meters that would charge on a time-of-day basis were expensive in those days and little progress occurred in the ensuring years. Even now, less than one percent of the more than 125 million electric customers in the United States are charged on a time-of-use basis.

However, the California energy crisis of 2000-01 reinvigorated interested in dynamic pricing, not only in that state but globally. Over the past decade, two dozen dynamic pricing studies featuring over one hundred dynamic time-of-use and dynamic pricing designs were carried out across North America, in the European Union and in Australia and New Zealand.[3]

These experiments have yielded a rich body of empirical evidence. We have compiled this into a database, *D-Rex*, which stands for *D*ynamic *R*ate *ex*periments. This contains the following data from each pilot: details of the specific rate designs tested in the pilot, whether or not enabling technologies were offered to customers in addition to the time-varying rates, and the amount of peak reduction that was realized with each price-technology combination. The *D-Rex* results provide an important perspective on the potential magnitude of impacts with different dynamic rate approaches and should inform the public debate about the merits of smart meters and smart pricing. Across the 129 dynamic pricing tests, peak reductions range from near zero values to near 60 percent values. However, it would be misleading to conclude that there is no consistency in customer response.[4]

We focus on nine of the best designed, more recent experiments to examine the impact of the peak to-off peak price ratio on the magnitude of the reduction in peak demand, or demand response. Because the amount of demand response varies with the presence or absence of enabling technology, such as a smart thermostat, an energy orb or an in-home display, we separate those pricing tests without and with enabling technology. We find a statistically significant relationship between the price ratio and the amount of peak reduction, and quantify this relationship with a logarithmic model. This relationship is termed the Arc of Price Responsiveness. We find that for a given price ratio, experiments with enabling technologies tend to produce larger peak reductions, and display a more price-responsive Arc.

Sidebar: The Dynamic Rates

[2] For an early summary, see Ahmad Faruqui and J. Robert Malko, "The Residential Demand for Electricity by Time-Of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Volume 8, Issue 10, October 1983. For more recent surveys, see Ahmad Faruqui and Jenny Palmer, "Dynamic Pricing and its Discontents," *Regulation*, Fall 2011 and Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity – A Survey of 15 Experiments," *Journal of Regulatory Economics*, October 2010. Faruqui and Palmer also discuss the more common myths that surround legislative and regulatory conversations about dynamic pricing.

[3] Most dynamic pricing studies have included multiple tests. For example, a pilot could test a TOU rate and a CPP rate and it could test each rate with and without enabling technology. Thus, this pilot would include a total of four pricing tests.

[4] See, for example, the concluding remarks in an otherwise excellent paper by Paul Joskow, "Creating a smarter U.S. electrical grid," *Journal of Economic Perspectives*, Winter 2012.

Time-of-Use (TOU). A TOU rate could either be a time-of-day rate, in which the day is divided into time periods with varying rates, or a seasonal rate into which the year is divided into multiple seasons and different rates provided for different seasons. In a time-of-day rate, a peak period might be defined as the period from 12 pm to 6 pm on weekdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the variation in marginal costs by pricing period.

Critical Peak Price (CPP). On a CPP rate, customers pay higher peak period prices during the few days a year when wholesale prices are the highest (typically the top 10 to 15 days of the year which account for 10 to 20 percent of system peak load). This higher peak price reflects both energy and capacity costs and, as a result of being spread over relatively few hours of the year, can be in excess of $1 per kWh. In return, the customers pay a discounted off-peak price that more accurately reflects lower off-peak energy supply costs for the duration of the season (or year). Customers are typically notified of an upcoming "critical peak event" one day in advance but if enabling technology is provided, these rates can also be activated on a day-of basis.

Peak Time Rebate (PTR). If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of peak-time rebate. Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply buy through at the existing rate. There is no rate discount during non-event hours. Thus far, PTR has been offered through pilots, but default (opt-out) deployments have been approved for residential customers in California, the District of Columbia and Maryland.

Real Time Pricing (RTP). Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers —above one megawatt of load — face hour-ahead prices. These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption at the most expensive times.

The Dynamic Pricing Studies

The *D-Rex* Database contains the results of 129 dynamic pricing tests from 24 pricing studies. [5] As shown in Figure 1, these results range from close to zero to up to 58 percent. Part of the variation in impacts comes simply from the fact that different rate types are being tested. Filtering by rate in Figure 2, some trends begin to emerge. We observe that the Critical Peak Pricing (CPP) rate tends to have higher impacts than Time-of-Use (TOU) rates, likely because the CPP rates have higher peak to off-peak price ratios. We can also filter by the presence of enabling technology, as in Figure 3, and observe that for the same rates, the impacts with enabling technologies tends to be higher.

[5] 23 of the 24 studies are pricing pilots. The other study is PG&E's full scale rollout of TOU and SmartRate.

Figure 1. Impacts from Residential Dynamic Pricing Tests, Sorted from Lowest to Highest

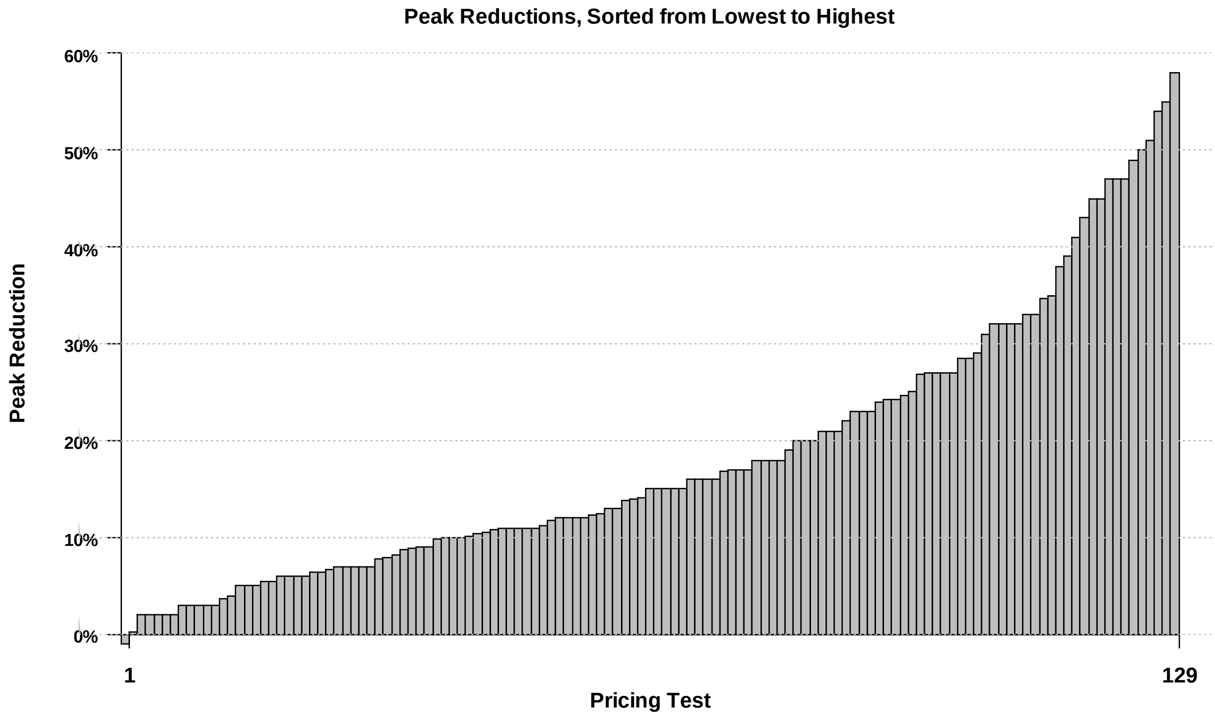
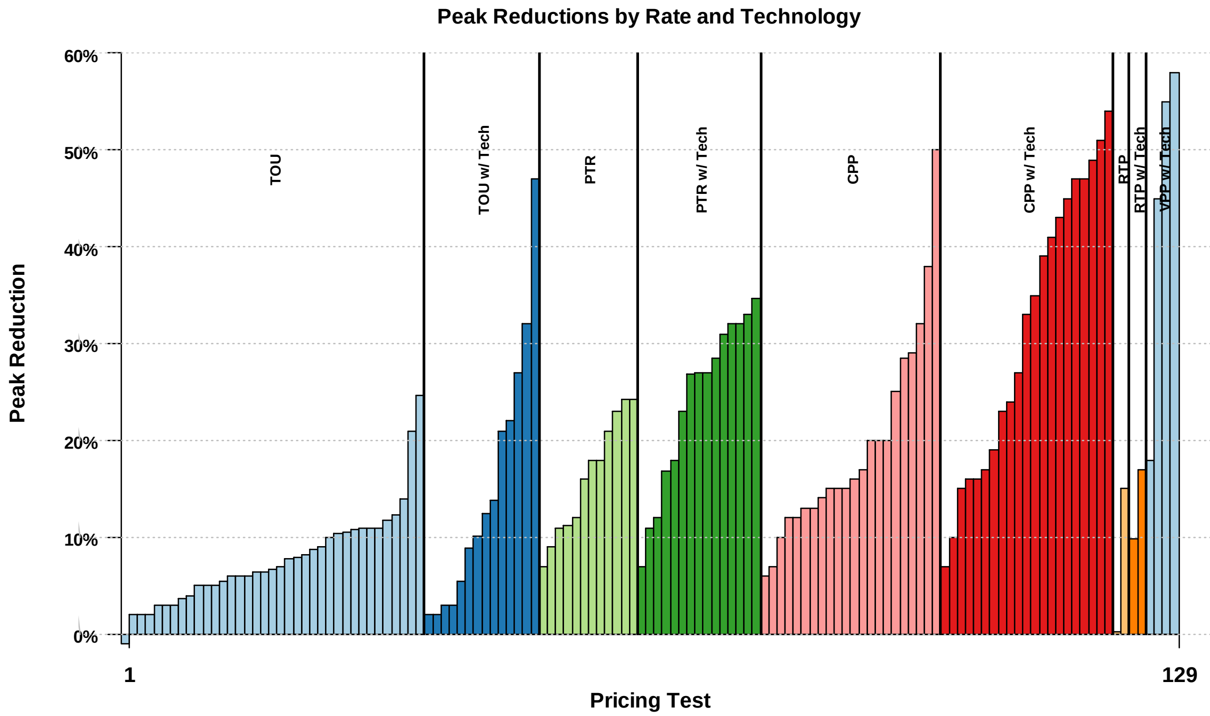


Figure 2. Impacts from Pricing Tests, by Rate Type

Figure 3. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies



Even with the rate and technology filters, there remains significant unexplained variation. In order to understand the cause of this variation, we first limit the sample to only the best-designed studies which have reported the relevant data. We selected studies in which samples are representative of the population and the results are statistically valid. Moreover, we selected studies in which participants were selected randomly, as opposed to volunteers responding to a mass mailing. The nine best-designed pilots, shown in Table 1, include 42 price-only tests and 32 pricing tests with prices *cum* enabling technology.[6] In these 74 tests, the peak reductions range from 0% to just under 50%. The remainder of this paper focuses on explaining the variation in these results.

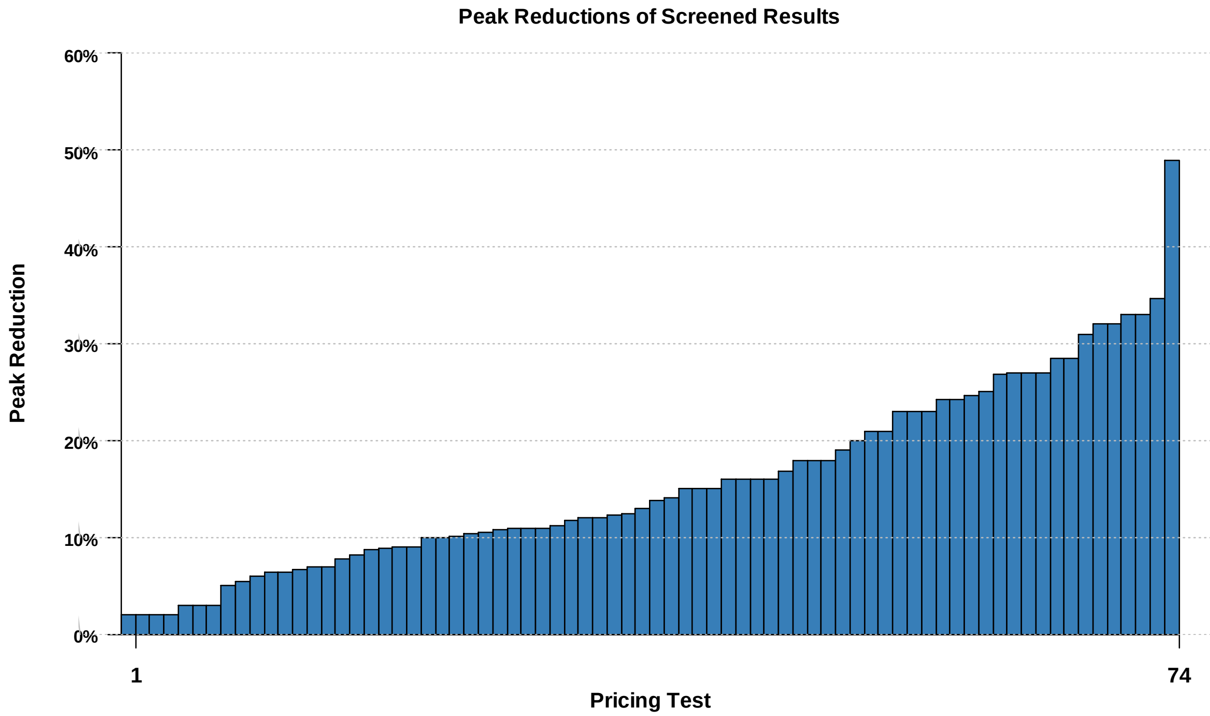
[6] OG&E was not included in these screened results because only the draft results are available thus far. When these results are finalized, they will be included in this analysis.

Table 1. Features of the Nine Dynamic Pilots

Utility	Location	Year	Rates	Enabling Technologies	Number of Tests
Baltimore Gas & Electric	Maryland	2008, 2009, 2010	CPP, PTR	CPP w/ Tech, PTR w/ Tech	17
Connecticut Light & Power	Connecticut	2009	TOU, CPP, PTR	TOU w/ Tech, CPP w/ Tech, PTR w/ Tech	18
Consumers Energy	Michigan	2010	CPP, PTR	CPP w/ Tech	3
Pacific Gas & Electric (Full scale rollout)	California	2009, 2010	TOU, CPP	Not tested	4
Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison (Statewide Pricing Pilot)	California	2003, 2004	TOU, CPP	CPP w/ Tech	4
Pepco DC	District of Columbia	2008, 2009	CPP, PTR, RTP[2]	CPP w/ Tech, PTR w/ Tech, RTP w/ Tech	4
Salt River Project	Arizona	2008, 2009	TOU	Not tested	2
Utilities in Ireland[2]	Ireland	2010	TOU	TOU w/ Tech	16
Utilities in Ontario	Ontario, Canada	2006	TOU, CPP, PTR	Not tested	6
				Total	**74**

1. Run by the Commission for Energy Regulation (CER)
2. The two RTP pricing tests are excluded from this analysis because they do not have a clear peak to off-peak price ratio.

Figure 4. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies

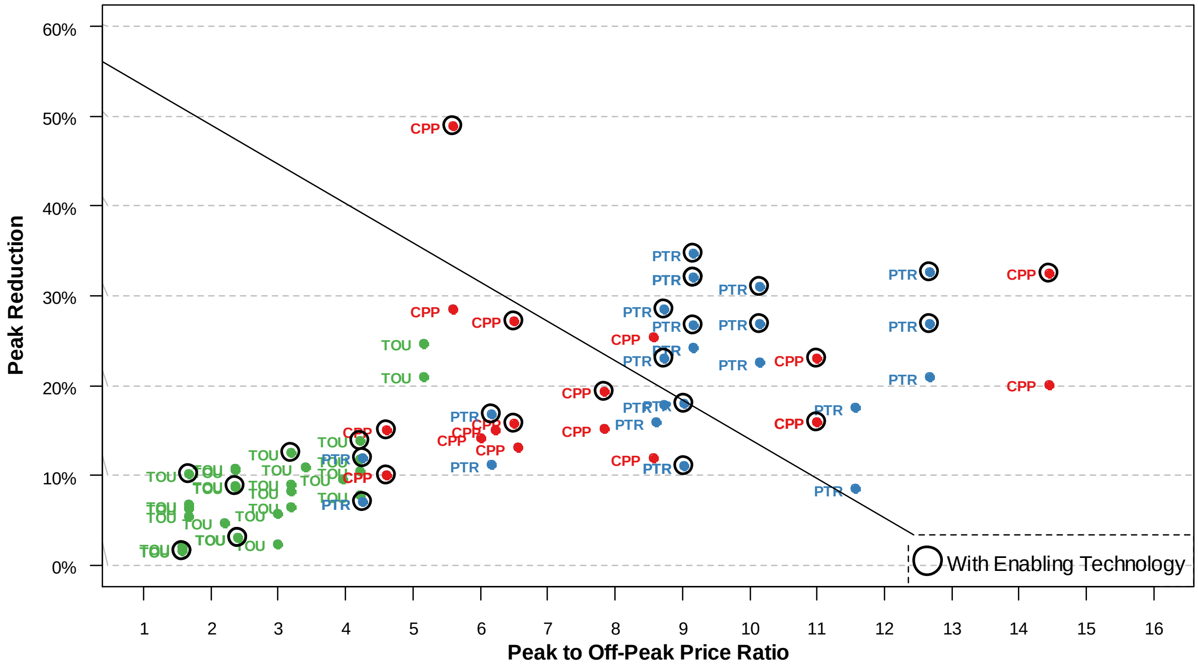


Methodology

The nine best-designed studies in *D-Rex* include 42 price-only test results and 32 price-cum-enabling technology test results for a total of 74 observations. For each result, we plot the all-in peak to off-peak price ratio against the corresponding peak reduction. As expected, the CPP and PTR rates tend to have higher peak to off-peak ratios than the TOU rates, with some overlap, and those rates with higher price ratios tend to yield greater peak reductions.[7] It also appears that that the enabling technology impacts may be greater than those with price only.

[7] For the PTR rate, the effective critical peak price is calculated by adding the peak time rebate to the rate that the customer pays during that time period.

Figure 5. Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Rate Type and Presence of Enabling Technologies



The plot suggests that peak impacts increase with the price ratio but at a decreasing rate. The logarithmic model would model rapid increases in peak reduction in the lower price ratios, followed by slower growth.[8]

Logarithmic Model

$$y = a + b * \ln(price\ ratio)$$

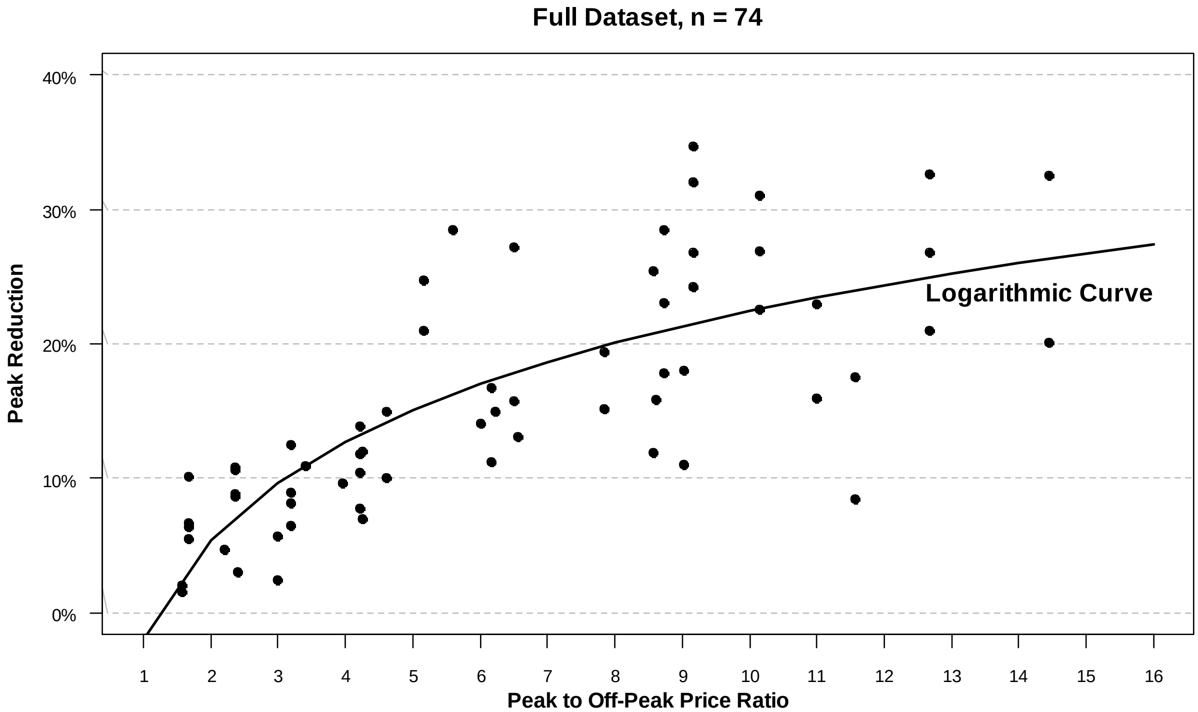
where $y = peak\ reduction\ percent$

Results

When we fit the logarithmic model to the full dataset (n = 74), it yields a coefficient of 0.106 with a standard error of 0.012, significant at the 0.001 level. In other words, as the price ratio increases, the peak reduction is also expected to increase. The peak-to-off-peak price ratio successfully explains 49 percent of the variation in demand response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction could be close to 30 percent.

[8] We also considered a logistic growth model that features slow growth at lower price ratios followed by moderate growth, followed by an upper bound peak reduction. The results were not significantly different with this functional form.

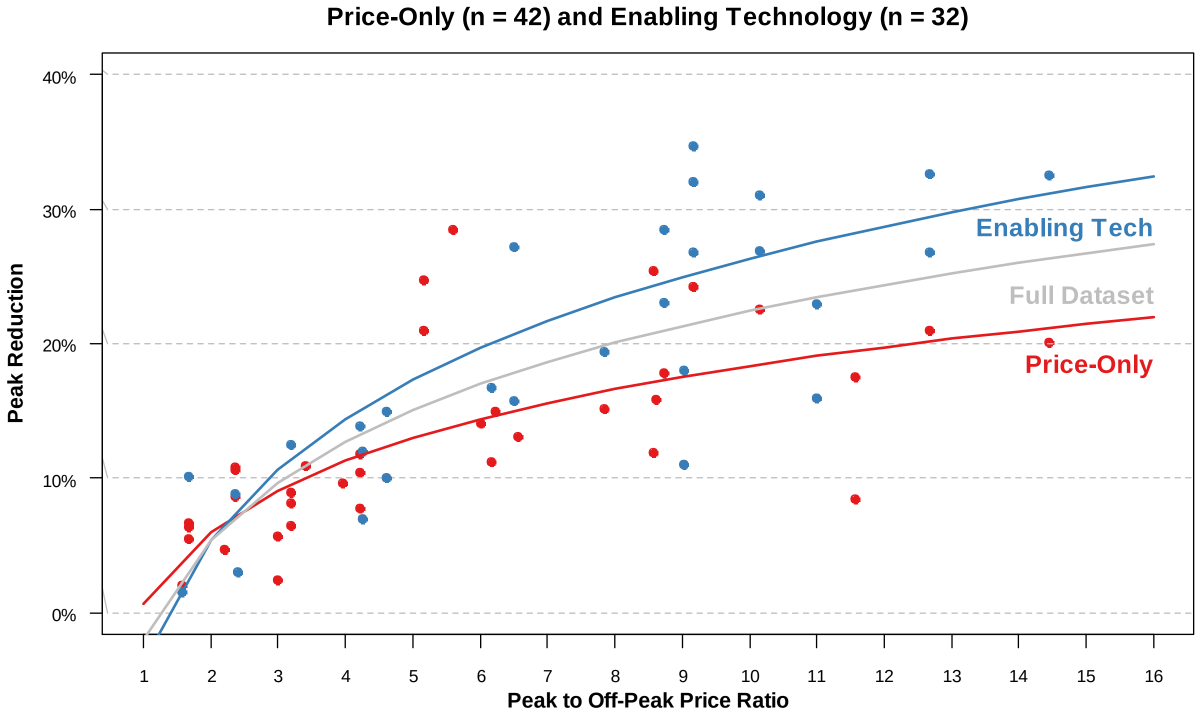
Figure 6. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curve



We can narrow down the model to focus on the price-only observations separately from the enabling technology observations. With this data, the model yields a coefficient of 0.077 with a standard error of 0.012, again significant at the 0.001 level. The coefficient is slightly lower here than in the full dataset, suggesting that the impacts increase more slowly in the absence of enabling technology. In this case, the adjusted R-squared value is 48 percent, meaning the ratio again explains almost half of the variation in response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction would be slightly over 20 percent.

With the enabling technology tests, we find that the curve has a steeper slope than the result with price-only tests. The coefficient of the enabling technology curve is 0.130 which has a standard error of .02. The regression successfully explains 53 percent of the variation in demand response. With a peak to off-peak ratio of 16, the peak reduction is expected to be over 30 percent.

Figure 7. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curves, Segregated by Presence of Enabling Technologies



The full regression results for the three different data specifications are shown in Table 2 below. In each case, the coefficient on the natural log of the price ratio is positive and significant at the 0.001 level.

Table 2. Regression Results

Coefficient	Full Dataset		Price-Only		Enabling Technology	
Ln(Price Ratio)	0.10611	***	0.07682	***	.13029	***
	(0.01254)		(0.01220)		(0.02164)	
Intercept	-0.01985		0.00654		-0.03668	
	(0.02234)		(0.02071)		(0.04080)	
Adjusted R-Squared	0.4916		0.4852		0.532	
F-Statistic	71.59		39.65		36.24	
Observations	74		42		32	

Standard errors are shown in parentheses below the estimates
*** = 0.001 significance
** = 0.01 significance
* = 0.05 significance

Conclusion

In our view, the results presented in this paper provide strong support for the deployment of dynamic pricing. They conclusively show that customers are responsive to changes in the price of electricity. In other words, they lower demand when prices are higher. Moreover, the results suggest that the presence of enabling technology allows customers to increase their peak reduction even further. These results may be used to quantify the potential peak reductions that may be expected when new dynamic rates are rolled out and to monetize these benefits using estimates of the avoided capacity of capacity and energy.[9]

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[9] On the monetization of benefits arising from smart meters and dynamic pricing in the context of the EU, see Ahmad Faruqui, Dan Harris, and Ryan Hledik, "Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," *Energy Policy*, 2010.

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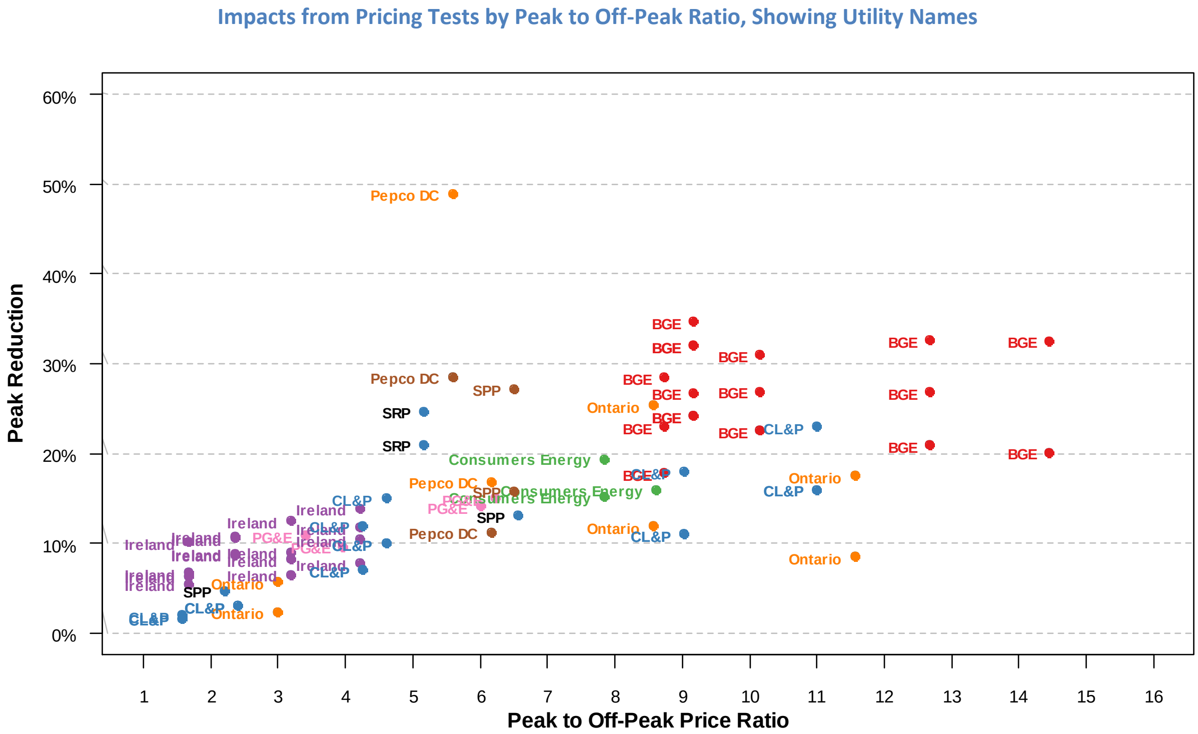
Biography of Authors

Ahmad Faruqui is a principal with The Brattle Group. He has been analyzing time-varying experiments since the beginning of his career in 1979 and his early work is cited in the third edition of Professor Bonbright's canon on public utility ratemaking. The author of four books and more than a hundred papers on energy policy, he holds a doctoral degree in economics from the University of California at Davis and bachelor's and master's degrees from the University of Karachi.

Jennifer Palmer is a research analyst at The Brattle Group. Since joining The Brattle Group in 2009, she has worked with a wide range of utilities on dynamic pricing and advanced metering projects. For several utilities, she has developed dynamic tariffs, simulated the impacts of these rates on customer consumption patterns, and estimated the resulting system-level benefits. She has a bachelor's degree in economics with a certificate in environmental studies from Princeton University.

Appendix


Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Utility Names
Peak Reduction
Peak to Off-Peak Price Ratio
60%
50%
40%
30%
20%
10%
0%
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
Pepco DC
BGE
SPP
SRP
Ontario
CL&P
Consumers Energy
Ireland
PG&E

Electricity Delivery
& Energy Reliability

American Recovery and
Reinvestment Act of 2009

Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

Smart Grid Investment

Grant Program

November 2016

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Appendix – Summary of CBS Time-Based Rate Offerings 72

Executive Summary

Time-based rate programs[1], enabled by utility investments in advanced metering infrastructure (AMI), are increasingly being considered by utilities as tools to reduce peak demand and enable customers to better manage consumption and costs.

SGIG Consumer Behavior Studies (CBS)

Ten SGIG CBS utilities conducted 11 consumer behavior studies in accordance with research protocols established by DOE. These studies were intended to answer key questions facing decision makers on customer acceptance, retention, and response and address the cost-effectiveness of using time-based rates to achieve utility, customer, and societal objectives. Further information can be found on Smartgrid.gov.

There are several customer systems that are relatively new to the marketplace and have the potential for improving the effectiveness of these programs, including in-home displays (IHDs), programmable communicating thermostats (PCTs), and web portals. Policy and decision makers are interested in more information about customer acceptance, retention, and response before moving forward with expanded deployments of AMI-enabled new rates and technologies.

Under the Smart Grid Investment Grant Program (SGIG), the U.S. Department of Energy (DOE) partnered with several electric utilities to conduct consumer behavior studies (CBS). The goals involved applying randomized and controlled experimental designs for estimating customer responses more precisely and credibly to advance understanding of time-based rates and customer systems, and provide new information for improving program designs, implementation strategies, and evaluations. The intent was to produce more robust and credible analysis of impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates.

To help achieve these goals, DOE developed technical guidelines to help the CBS utilities implement experimental designs that would provide more accurate estimates of customer acceptance, retention, and response. The guidelines were also intended to help the utilities identify the key drivers motivating customers to join programs and take actions to change their

[1] Time-based rates are electricity prices that vary with time and are intended to provide consumers with price signals that better reflect the time-varying costs of producing and delivering electricity.

electricity consumption behaviors. In addition, DOE provided a team of technical experts to help each utility focus their study efforts to better address long-term objectives.

There were ten CBS utilities conducting eleven studies. They comprised a generally representative group of utility types, sizes, and regions of the country. As shown in Table ES-1, each of the CBS utilities evaluated at least one of four types of time-based rate programs: critical peak pricing (CPP), critical peak rebates (CPR), time-of-use (TOU) pricing, and variable peak pricing (VPP).[2] In addition to rates, the CBS utilities also evaluated a variety of non-rate elements in their studies including information and automated control technologies as well as education. Lastly, all the CBS utilities employed an opt-in (voluntary) recruitment approach to their studies, while two augmented that effort with a separate opt-out approach (where customers are automatically defaulted on time-based rates).

Table ES-1. Scope of the Consumer Behavior Studies

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

[2] Technically, CPR is not a time-based rate; it is an incentive-based program. For presentation purposes it is classified with the other time-based rate programs.

All of the studies are complete. This report presents results from the interim and final evaluations for all 10 of the CBS utilities.[3]

Major Findings

There are five areas that results from the CBS utilities can be grouped into:

(1) Recruitment approaches – effects of opt-in and opt-out;
(2) Pricing versus rebates – effects of CPP and CPR;
(3) Customer information technologies – effects of IHDs;
(4) Customer control technologies – effects of PCTs; and
(5) Customer response to prices – effects of TOU.

Each is discussed in turn below and summarized in Table ES-2.

Recruitment Approaches – Effects of Opt-in and Opt-out

Social scientists have long recognized a behavioral phenomenon called the "default effect" or "status quo bias" – when facing choices that include default options, people are predisposed to remain on a pre-selected (i.e., default) option rather than choose alternative options. If the status quo bias holds true, then opt-out recruitment efforts for time-based rates would result in much higher enrollment levels than opt-in approaches. On the other hand, utilities and others generally expect customers to drop out at higher rates, and peak demand reductions to be lower, under default opt-out approaches than those recruited voluntarily under opt-in.

Results from the CBS utilities show that under opt-out recruitment approaches enrollment rates were indeed much higher (92% vs. 15%) and peak demand reductions were generally lower (6% vs. 12% for TOU and 13% vs. 23% for CPP) than under voluntary enrollment methods. However, retention rates were about the same for both (90% vs. 87%). From these results, one would expect larger aggregate peak demand reductions from comparably sized populations of customers solicited for TOU or CPP using opt-out versus opt-in approaches. Also, the overall cost-benefit advantages are expected to be greater for opt-out approaches than opt-in approaches since efforts to default customers on rates require less effort than enrolling

[3] All of the CBS utilities' evaluation reports can be accessed from the Consumer Behavior Study section of smartgrid.gov. In addition, a number of other CBS related documents relating to guidance provided to the CBS utilities as well as additional evaluation results can be found.

volunteers. We observed benefit-cost ratios greater than 2.0 for opt-out and between 0.7 and 2.0 for opt-in, depending on rate and technology combination.[4]

Prices versus Rebates – Effects of CPP and CPR

The behavioral science theory of loss aversion states that when people are presented with a choice that involves the potential of either avoiding a loss or acquiring a gain, the strong preference is to avoid the loss rather than to acquire the gain. As a result, one would expect that customers would be more likely to enroll in and remain on CPR than CPP. The perceived risk of receiving higher bills from under performance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention for CPP. However, once customers are on a rate, because the risk of potential loss from CPP is more salient than the potential gain from CPR, customers are expected to respond more to CPP.

Results from the CBS utilities support this theory as retention rates were higher for CPR (89%) than for CPP (80%) and demand reductions were generally higher for CPP (21%) than for CPR (11%), whereas the variability in average demand reductions across events was less for CPP than it was for CPR. However, when PCTs were available as an automated control strategy, the differences in average peak demand reductions between CPP and CPR were largely eliminated. This suggests that regardless of the financial incentive to respond (i.e., acquiring a gain via a rebate or avoiding a loss via pricing), PCTs can be an effective tool to mitigate a customer's loss aversion by allowing them to automate their response during the critical peak events.

[4] The SMUD benefit-cost results are based on a ten year net present value analysis. The benefits were based on the deferral value of capacity additions and avoided wholesale energy costs due to reduced loads during high cost periods or shifting usage from higher to lower cost periods. The costs were based on marketing, program administration and technology expenses. See Section 10.1 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

Table ES-2. Summary of Major Findings	
Area	**Major Findings – Demand Reductions & Enrollment/Retention Rates**
Recruitment Approaches – Opt-in & Opt-out	• Opt-out enrollment rates were about 3.5 times higher than they were for opt-in (93% vs. 15%). • Retention rates for opt-out recruitment approaches (85.5% in year 1 and 88.5% in year 2) were about the same as they were for opt-in (89.7% in year 1 and 91.0% in year 2). • Peak period demand reductions for SMUD's opt-in TOU customers were about twice (13% in year 1 and 11% in year 2) as large as they were for opt-out customers (6% in year 1 and year 2). • Peak period demand reductions for SMUD's opt-in CPP customers were about 50% higher (24% in year 1 and 22% in year 2) than they were for opt-out customers (12% in year 1 and 14% in year 2). • SMUD's opt-out offers were more cost-effective for the utility than their opt-in offers in all cases. • Roughly two-thirds of those who were defaulted onto SMUD's TOU rates were expected to see bill impacts of +/- $20 for the entire 4 summer months the rates were in effect. • Based on survey responses, a majority of those defaulted onto SMUD's TOU rate were satisfied with the rate, regardless of the level of bill savings achieved, but those who saw the largest bill increases were generally less interested in continuing with the rate after the study ended.
Pricing Versus Rebates – CPP & CPR	• While opt-in enrollment rates for GMP were about the same for CPP (34%) and CPR (35%), retention rates were somewhat lower for CPP (80%) than they were for CPR (89%). • Average peak demand reductions for CPP (20%) were about 3.5 higher than they were for CPR (6%), but when automated controls (PCTs) were provided, they were about 30% larger (35% for CPP and 26% for CPR).
Customer Information Technologies - IHDs	• Enrollment and retention rates were generally unaffected by offers of IHDs. • SMUD's opt-in CPP customers with IHDs (26% in year 1 and 24% in year 2) had somewhat higher peak demand reductions than those without IHDs (22% in year 1 and 21% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's opt-in TOU customers with IHDs (13% in year 1 and 11% in year 2) had somewhat higher peak demand reductions than those without IHDs (10% in year 1 and 9% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's offerings without IHDs were more cost-effective for the utility in all cases than those with IHDs.
Customer Control Technologies - PCTs	• Enrollment and retention rates were generally unaffected by offers of PCTs. • Peak demand reductions are generally higher for CPP and CPR customer with PCTs (22% to 45%) than they were for customers without PCTs (-1% to 40%). • OG&E rate offers with PCTs were more cost-effective for the utility than those without PCTs.
Customer Response to Price - TOU	• Peak period demand reductions were far less, on average, for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak price ratio greater than 4:1). • When a CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction rose to 27% when averaged over all of the treatments • When PCTs were available, the differences in average peak period demand reductions were only affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1).

Customer Information Technologies – Effects of IHDs

Customer information technologies such as IHDs and web portals provide ways of raising customer awareness about usage levels, consumption patterns, electricity prices, and costs. By raising awareness about prices and usage patterns, utilities create opportunities for customers to better understand how usage affects their bills. With this information, utilities expect customers will have better capabilities for understanding and responding to time-based rates. When IHDs are offered by utilities to customers for free (which is frequently done to bolster participation rates) implementation costs increase, so it is important to understand if the benefits outweigh the costs of the devices.

Results from the CBS utilities show that free IHD offers did not make a substantial difference for enrollment and retention rates (+/- 1-4 percentage points). Although SMUD's peak demand reduction estimates were larger with IHDs (2-3 percentage points), this result can be attributed to pre-treatment differences between the two groups so there was not a measured IHD effect on reductions of peak demand. As a result, because the cost of providing IHDs is non-negligible, the benefit-cost ratios of rate offerings were lower when they included offers of free IHDs relative to when they were absent (0.74 vs. 1.19 for TOU and 1.30 vs. 2.05 for CPP). In addition, many of the CBS utilities reported significant challenges with this relatively new technology. Problems included very low customer connectivity rates (e.g., less than 20% were connected all the time while between 42% and 65% were never connected at all), getting the IHDs to function properly (e.g., binding to the meter to receive data) and in one case the manufacturer decided to halt production and stop support in the middle of the study.

Customer Control Technologies – Effects of PCTs

Conceptually, automated control technologies such as PCTs lower the transactional effects associated with responding to prices and critical peak events by making it easier for customers to alter their electricity consumption at specified times. As with IHDs, utility offers of free PCTs cause implementation costs to increase, so it is important to understand if the value of the additional demand reductions outweighs the costs of the devices.

Although the studies were not designed and implemented in such a way as to measure the effect of PCTs on enrollment, results from the CBS utilities show that free PCT offers did not make a major difference for retention (91% with or without PCTs). However, peak demand reductions were substantially higher when a PCT was present (22-45% reduction with a PCT vs. -1 to 40% without one) while the variability of those reductions was less, which should increase the value of such demand reductions. Unlike with IHDs, benefit-cost ratios for PCT offers were favorable (i.e., greater than 1.0). In response, one utility (OG&E) decided to roll-out a time-based rate with an offer of a free PCT to its entire residential customer class with a recruitment goal of 120,000 customers within three years.

Customer Response to Prices – Effects of TOU

Economic theory suggests that people are generally willing to buy larger quantities of a good as its price goes down. Conversely, as the price increases, people are expected to buy less of that same good. This basic relationship can be used to explain what the CBS utilities expected to happen when they introduced a TOU rate into their study: electricity consumption would be reduced in the peak period when the peak period price of electricity was raised relative to the price of electricity in the off-peak period.

The estimated demand reductions during the peak period from customers exposed to a TOU rate ranged from a low of -1% (i.e., load increased for the average customer in this TOU treatment by 1%) to a high of 29%, with an average of 15%. On average, customers responded to a greater extent (i.e., reduced their peak demand to a greater extent) when exposed to higher rather than lower price ratios. Results indicate that customers reduced demand during the peak period by 6%, on average, when experiencing a peak to off-peak price ratio less than 2:1 compared to 18% when experiencing a price ratio greater than 4:1. However, when PCTs were available as an automated control strategy, the variability of peak period demand reductions was significantly reduced and greater reductions were observed for price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1). This suggests that PCTs can be an effective tool in augmenting peak period demand reductions, but only if the price ratio is high enough. When CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction was 27% when averaged over all of the treatments. However, when PCTs were available, the average event peak demand reduction was 34% vs. 24% when such automated control technology was not available.

Concluding Remarks

Rigorous experimental methods were applied in these consumer behavior studies with the belief that more credible and precise load impact estimates would help resolve some of the outstanding issues hindering broader industry adoption of time-based rates for residential customers. Since none of the CBS utilities had any experience with such experimental methods, each CBS utility was provided with a small team of industry experts who provided technical assistance in the design, implementation and evaluation of each study. Besides direct engagement with each CBS utility, these Technical Advisory Groups (TAGs) also produced a library of guidance documents for the CBS utilities (publicly available on smartgrid.gov) on such diverse topics as study plan documentation, experimental design, rate and non-rate treatments, and evaluation techniques. With the help of these TAGs and the reference material they produced, many of the concerns initially raised about the application of experimental methods (e.g., that withholding or deferring exposure to the rate after a customer had agreed to participate in the study would create customer relations problems) did not materialize. In addition, TAGs helped the utilities more narrowly focus their studies on a core set of objectives that would more directly inform the utilities on suitable pricing strategies. As such, the consumer behavior study program produced results that significantly contributed to our understanding of several critical issues, as described above.

Both utilities and participating customers learned a tremendous amount about themselves and their capabilities through these studies. Although not an explicit objective of the consumer behavior studies, successful recruitment into the pricing studies hinged on the ability of the CBS utilities to effectively engage customers – many of whom had very limited experience in this arena. As such, several CBS utilities recognized the importance of performing market research during the study design phase to ensure marketing material was as effective as possible to engage customers as participants in the studies. The most successful CBS utilities continued that engagement not just during recruitment but throughout the study period itself, which included the creation of a plethora of different materials using a number of different mediums (e.g., monthly newsletters, social media campaigns of tips and tricks) that constantly sought to keep customers engaged in the study. Such efforts seemed to be quite successful, as the vast majority of customers who started the studies also completed them, expressed a high level of satisfaction in their experiences with these new rates and to a lesser extent with the new technologies, and continued taking service under the rate after the study ended, provided such opportunities were available.

The results of the consumer behavior study effort has helped the participating utilities and others to advance the application of time-based rates. Three of the ten CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the ten CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. Specifically, OG&E has enrolled approximately 116,000 of their residential customers (representing approximately 18% of their residential population) on their SmartHours program, 100,000 (86%) of which are taking service on the variable peak pricing rate tested in its CBS, and are achieving 147 MW of peak demand reduction. This voluntary SmartHours program includes the offer of a free PCT, which 90% of customers have taken. SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing heavily the very positive results SMUD achieved as grounds for this decision. DOE hopes the experiences and results from the CBS effort will help the industry to effectively consider the application of time-based rates for residential customers.

1. Introduction

Time-based rates, enabled by utility investments in advanced metering infrastructure (AMI), are increasingly being considered by utilities and policy makers as tools to augment incentive-based programs for reducing peak demand and enabling customers to better manage consumption and costs. In addition, there are several customer systems that are relatively new to the marketplace that have potential for improving the effectiveness of these programs, including in-home displays (IHDs), programmable communicating thermostats (PCTs), web portals, and a host of new and novel software and data applications.[5]

The electric power industry is interested in more information about residential customer preferences for and responses to time-based rates and incentive-based programs as utilities and other stakeholders propose plans for expanded deployments. Under the U.S. Department of Energy's (DOE) Smart Grid Investment Grant Program (SGIG), several utilities took part in a Consumer Behavior Study (CBS) effort in order to develop information on preferences and responses to time-based rates and incentive-based programs, including impacts, benefits, and lessons-learned that could inform utilities' and policy makers' decisions about the design and implementation of new rate and technology offerings.

1.1 Background about Time-Based Rates and Advanced Metering Infrastructure

From the early days of the electric power industry, utilities, policy makers, and academics have shown interest in time-based rates for electricity.[6] When designed correctly, such rates allow the prices that customers pay to use electricity to correspond more closely to the actual costs of producing or procuring it. For most utilities, the cost of providing electricity changes over a variety of different time dimensions: minute, hour, day, month, and season. In general, as demand for electricity increases, higher-cost power plants must be brought online to accommodate the additional demand. Furthermore, the variable nature of certain types of renewable generation technologies likewise can cause power costs to fluctuate. Figure 1 shows how different types of time-based rates can reflect to varying degrees the marginal costs of producing electricity. Although not shown in the figure, real-time pricing (RTP), in its ideal form, can perfectly reflect these marginal costs. The alternative rates shown in the figure, critical peak pricing (CPP), variable peak pricing

[5] For example, the Green Button initiative which provides a standard protocol for customers to gain access to their interval meter data.

[6] Hausman, W. J. and J. L. Neufeld (1984). "Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century." The Rand Journal of Economics 15(1): 116-126.

(VPP), and time-of-use (TOU), all seek to reflect at a more aggregate level the average of the marginal cost of producing electricity during various periods of time.

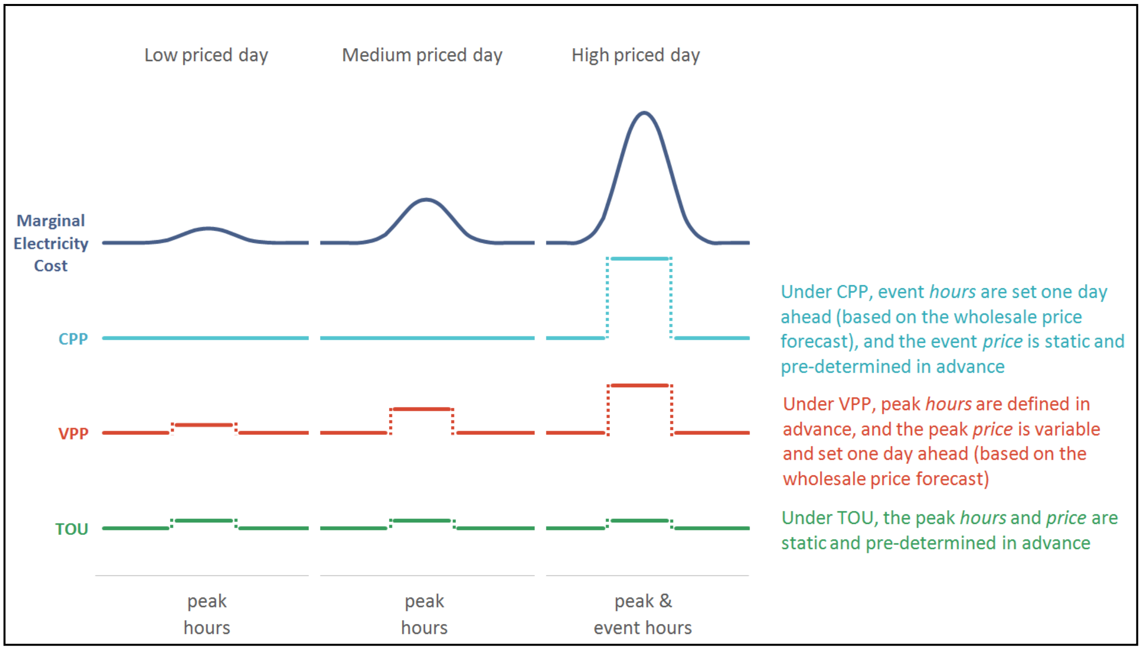


Figure 1. An Illustration of Several Time-Based Rate Designs.

Furthermore, a myriad of financial benefits inure to utilities and their ratepayers when customers take service under and respond to time-based rates. The value associated with lowering peak demands is often at its highest when reductions in consumption coincide with times that the local or regional power system is experiencing its highest level of demand (i.e., the coincident system peak demand). Such reductions in electricity demand at these times can lead to future deferrals of new investments or upgrades in electric generation, distribution and possibly transmission facilities, and/or avoidance of higher prices or demand charges from wholesale power suppliers. These results can lead to reductions in the utility's overall cost of service, which can benefit all customers when the reductions are passed on through retail rates.

In 1978, the U.S. Congress saw the value of trying to move the electric power industry towards more time-based pricing and passed The Public Utility Regulatory Policies Act[7] (PURPA). This legislation contained standards calling for states to consider adoption of TOU rates to better reflect the costs of service by charging prices that encouraged customers to shift consumption from more expensive peak to less expensive off-peak periods. In response to PURPA, many states implemented TOU rates

[7] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether or not it is appropriate to implement TOU rates and other ratemaking policies.

on a pilot basis to evaluate their cost-effectiveness. During the early 1980s, evaluations of those pilot programs by the Federal Energy Administration (a DOE predecessor) found that customers responded to TOU rates and successfully shifted electricity use from higher to lower cost times of day.[8] However, the costs of new meters capable of measuring consumption by time-of-day presented a barrier at that time to cost-effective implementation of TOU rates on a larger scale.

In spite of this, interest by state policy and decision makers in deployments of time-based rate programs has remained. In fact, more than 100 studies have been published that assess how customers change their consumption patterns in response to time-based rate programs, including assessments of how customer responses are helped or hindered by access to usage information from web portals and in-home displays, or by use of control technologies that automate electricity-consuming devices such as programmable communicating thermostats.[9] Results from these studies vary widely[10] and many policy and decision makers continue to ask for more detailed and more precise information about key policy questions, including:

- Does the enrollment condition (i.e., opt-in, opt-out) affect customer acceptance, retention and/or response to a time-based rate?
- Does the existence of control and/or automation technology (e.g., programmable communicating thermostat) affect customer acceptance, retention and/or response to a time-based rate?
- Does the existence of information technology (e.g., in-home display) affect customer acceptance, retention and/or response to a time-based rate?
- Do customer demographics (e.g., low-income, high usage, elderly households, college educated) play a role in customer acceptance, retention, and/or respond to a time-based rate?
- What is the persistence of participation and response over time to a time-based rate?
- What role does bill protection and/or bill guarantees have on customer acceptance, retention and/or response to a time-based rate?

Over the past 15 years, the costs of interval meters and the communications networks to connect the meters with utilities and back-office systems (i.e., advanced metering infrastructure, or AMI)

[8] Faruqui, A. and J. R. Malko (1983). "The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing." Energy 8(10): 781-795.

[9] Faruqui, A. and S. Sergici (2010). "Household Response to Dynamic Pricing of Electricity-A Survey of the Empirical Evidence." Social Sciences Research Network.

[10] EPRI (2012). Understanding Electric Utility Customers: What we know and what we need to know. EPRI. Palo Alto, CA.

have decreased. Recent implementation of AMI allows electricity consumption data to be captured, stored and reported at 5 to 60-minute intervals and provides opportunities for utilities and policymakers to reconsider the merits of widespread deployment of time-based rates. The benefits which may result from the application of time-based rates often times helps to justify the business case for investments in AMI. In addition to enabling time-based rates, AMI also provides new opportunities for utilities to lower costs by automating meter reading, service connections and disconnections, and tamper and theft detection. AMI can also lower electric distribution costs through improvements in outage management and voltage controls.[11]

At present, many regulators, policy makers, and other stakeholders are seeking more definitive answers to key policy questions as well as more accurate estimates of value-streams before supporting AMI investments and expanded implementation of time-based rates for residential and small commercial customers.

1.2 Overview of DOE's Consumer Behavior Studies (CBS) Program

In 2009, Congress saw an opportunity to advance the electricity industry's investment in the US power system's infrastructure by including the Smart Grid Investment Grant (SGIG) as part of the American Recovery and Reinvestment Act (Recovery Act). To date, DOE and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared SGIG projects that seek to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations enabled by these investments. The SGIG program included more than 60 projects that involved AMI deployments with the aim of improving operational efficiencies, lowering costs, improving customer services, and enabling expanded implementation of time-based rate programs.[12]

In selecting project applications for SGIG awards, DOE was interested in working closely with a subset of utilities willing to conduct comprehensive consumer behavior studies that applied randomized and controlled experimental designs. DOE's intent for the studies was to encourage the utilities to produce robust statistical results on the impacts of time-based rates, customer information systems, and customer automated control systems on peak demand, electricity consumption, and customer bills. The intent was to produce more robust and credible analysis of

[11] DOE's Recovery Act smart grid programs have produced a number of reports and case studies documenting the impacts and financial benefits of AMI for these purposes. These can be downloaded from www.smartgrid.gov.

[12] SGIG has helped to deploy more than 16.3 million new smart meters, which represents about 32% of the 50 million smart meters that have been installed nationwide as of 2015.

impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates. Of the SGIG projects investing in AMI and implementing time-based rate programs, there were ten utilities that were interested in working with DOE to participate in the CBS program.

The ten CBS utilities set out to evaluate a variety of different time-based rate programs and customer systems. Concerning the former, the CBS utilities planned to study TOU, CPP, VPP, and critical peak rebates (CPR).[13] Many also planned to include some form of customer information system (e.g., IHDs) and/or customer automated control system (e.g., PCTs). Several CBS utilities evaluated multiple combinations of rates and customer systems, based on the specific objectives of their SGIG projects and consumer behavior studies. For example, one utility evaluated treatment groups with a CPP rate layered on top of a flat rate, in combination with and without IHDs. Another evaluated VPP as well as CPP layered on top of a TOU rate in combination with and without PCTs.

1.3 DOE's Technical Approach to the CBS Program

DOE's goal for all of the consumer behavior studies was for them to produce load impact results that achieve internal and ideally external validity.[14] To help ensure that this goal was met, DOE published ten guidance documents for the CBS utilities. The guidelines were intended to help the utilities better understand DOE's expectations of their studies to achieve these goals, including their design, implementation, and evaluation activities.

Specifically, several of the DOE guidance documents addressed how to appropriately apply experimental methods such as randomized controlled trials and randomized encouragement designs to more precisely estimate the impact of time-based rates on electricity usage patterns, and identify the key drivers that motivated changes in behavior.[15] The guidance documents identified

[13] Technically, CPR is not a time-based rate; it is an incentive-based program. However, for simplicity of presentation, it is classified with the other event-driven time-based rate programs.

[14] Internal validity is the ability to confidently identify the observed effect of treatments, and determine unbiased estimates of that effect. External validity is the ability to confidently extrapolate study findings to the larger population from which the sample was drawn.

[15] The experimental designs were intended to ensure that measured outcomes could be determined to have been caused by the program's rate and non-rate treatments, and not random or exogenous factors such as the local economic conditions, weather or even customer preferences for participating in a study. Most of the studies decided to use a *Randomized Controlled Trial* experimental design, which is a research strategy involving customers that volunteer to be exposed to a particular treatment and are then randomly assigned to either a treatment or a control group. A few studies chose to use a *Randomized Encouragement Design*, which is a research strategy involving two groups of customers selected from the same population at random, where one is offered a treatment while the other is not. Not all customers offered the treatment are expected to take it, but for analysis purposes, all those who are offered the

key statistical issues such as the desired level of customer participation, which was critical for ensuring that sample sizes for treatment and control groups were large enough for estimates of customer response to have the desired level of accuracy and precision. Without sufficient numbers of customers in control and treatment groups, it would be difficult to determine whether or not differences in the consumption of electricity were due to exposure to the treatment or random factors (i.e., internal validity).

To make best use of the guidance documents, DOE assigned a Technical Advisory Group (TAG) of industry experts to each CBS utility to provide technical assistance. The TAGs helped customize the application of the guidance documents as each of the utility studies was different and had their own goals and objectives, starting points, levels of effort, and regulatory and stakeholder interests. These latter factors, in conjunction with the DOE guidance documents, determined how each utility study was designed and implemented. For example, several utilities had prior experience with time-based rates and used the studies to evaluate needs for larger-scale roll-outs. Others had little or no experience and used the studies to learn about customer preferences and assess the relative merits of alternative rates and technologies.

Each CBS utility was required to submit a comprehensive and proprietary Consumer Behavior Study Plan (CBSP) that was reviewed by the TAG and approved by DOE. In its CBSP, each utility documented the proposed study elements, including the objectives, research hypotheses, sample frames, randomization methods, recruitment and enrollment approaches, and experimental designs. The CBSP also provided details surrounding the implementation effort, including the schedule for regulatory approval and recruitment efforts, methods for achieving and maintaining required sample sizes, and methods for data collection and analysis.[16]

Each CBS utility was also required to comprehensively evaluate their own study and document the results, along with a description of the methods employed to produce them, in a series of evaluation reports that were reviewed by the TAG, approved by DOE, and posted on Smartgrid.gov. Each utility was expected to file an interim evaluation report after the first year of the study and a final evaluation report at the end of the study.

treatment are considered to be in the treatment group. For more information, see **"**Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines" July 2013, Lawrence Berkeley National Laboratory.

[16] In several cases, utilities encountered problems during implementation (e.g., insufficient numbers of customers in certain treatment groups) that required the study's initial design as described in the CBSP to be altered to maintain a high probability of achieving as many of the study's original objectives as possible. For several utilities this meant reductions in the number of treatment groups included in the studies.

1.4 Reporting

In addition to the CBS utilities' evaluation reports, DOE funded research on a variety of topics related to this CBS effort utilizing independent analysis of data collected by the CBS utilities throughout their studies.[17] Some of these reports are for a general audience and can be found on DOE's smart grid website (smartgrid.gov). A number of other reports, which are considerably more technical in nature, can be found at Lawrence Berkeley National Laboratory's (LBNL) website (emp.lbl.gov). Finally, a small subset are highly technical and will be published in peer-reviewed academic journals.

Table 1 lists the title of each report that has already been published as a DOE report (smartgrid.gov) or an LBNL report (emp.lbl.gov) as well as when it was published.

Table 1. Prior SGIG CBS Reports

Titles	Publication Location	Publication Dates
Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies	Smartgrid.gov	June 2013
Residential Customer Enrollment in Time-based Rate and Enabling Technology Programs	Smartgrid.gov	June 2013
Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies	Smartgrid.gov	July 2013
Experiences from the Consumer Behavior Studies on Engaging Customers	Smartgrid.gov	September 2014
Time-of-Use as a Default Rate for Residential Customers: Issues and Insights	Emp.lbl.gov	June 2016
Experiences of Vulnerable Residential Customer Subpopulations with Critical Peak Pricing	Emp.lbl.gov	September 2016

Those research activities that DOE continues to fund, which include an analysis of the data collected by the CBS utilities through their consumer behavior studies, will include the following topics, which will be reported separately as LBNL reports and/or as peer-reviewed journal articles:

- **Go for the Silver? Comparing Quasi-Experimental Methods to the Gold Standard**

[17] This rich dataset includes: study assignment, participation and retention data; interval meter data; survey data; customer systems data; and other data collected during the course of each study.

Randomized controlled trials (RCTs) are widely viewed as the "gold standard" for evaluating the effectiveness of an intervention. However, analysis of the effect of energy pricing has largely been conducted through quasi-experimental methodologies. Analyzing interval meter data from a subset of the CBS utilities, the true estimates obtained through the RCT will be compared with those derived from an application of quasi-experimental designs as well as from a regression discontinuity design. The goal will be to identify what might be causing any observed bias when non-RCT methods are used in this setting.

- **Understanding What Drives the Bias in Baseline Methods for Evaluating Demand Reduction**
  This research expands upon the comparison of impact estimates from experimental and quasi-experimental designs in order to delve deeper into an examination of the bias of the current best performing baseline methods in an attempt to identify the cause and implications of this bias. By analyzing interval meter data from the Sacramento Municipal Utility District's consumer behavior study, the cause of the bias can hopefully be identified: spillover, in which customers reduce demand not only during the hours that the program is designed to target, but also during other hours. The analysis will also attempt to understand the conditions under which the bias is bigger or smaller (e.g., temperature of event days; temperature of the days preceding the event; length of time between events; length of time customers have been enrolled in the CPP rate).

1.5 Data Sources

This report summarizes the major findings of DOE's SGIG-funded consumer behavior studies of time-based rates. A key source of information for the results reported herein comes from the interim and final evaluation reports that were submitted by the CBS utilities to DOE. However, not all of the utilities designed their studies to produce results that were perfectly comparable, reported information in the same way, or included metrics using the same analytical methods. When possible, this report presents aggregated results using comparable data from two or more of the utilities. Results from individual utilities are also presented where appropriate to highlight key findings. In general, the findings in this report address the following topics[18]:

[18] An assessment of bill impacts which incorporate the effects of customer response to time-based rates was not undertaken. Event driven rates are designed to be revenue neutral based on the dispatch of a specific number of events where a dramatically higher rate is in effect. If not all of those events are actually called during the study relative to the number used in designing the rate, then participating customers are highly likely to experience bill savings. This is not necessary reflective of their efforts to reduce or shift load during events, but rather an artifact of the rate design. As such, a reporting of bill impacts out of the consumer behavior studies could be misleading, since most of the studies

- The choices made by participating customers to enroll, accept, and remain involved in time-based rates. This includes information about the effects on customer choices from different forms of recruitment (i.e. opt-in versus opt-out), customer systems (i.e., IHDs and PCTs), and time-based rate offerings (i.e., CPP, CPR).
- The customer responses in terms of customer electricity demand reductions that stem from the application of different recruitment methods, customer systems, and time-based rates.
- The cost-effectiveness of the rates, programs, and customer-systems for the utility.[19]

The contents of any prior DOE-funded independent analysis of the data generated by the CBS utilities also serves as reference material for the results reported herein and is noted accordingly.

who included some form of CPP (which was a majority of the studies as will be discussed in Chapter 2) did not call all of the events for which the rate was designed for.

[19] However, there was limited information in the evaluation reports on this topic.

2. Scope and Status

Because each utility had its own unique study objectives, it is important to understand some of the details about each of the studies to more fully frame the results, and their implications. Each of the study summaries presented below contains a description of the overall SGIG project and to the study itself.[20] The Appendix contains additional information on the rates offered by the CBS utilities.

2.1 Types of Rate and Non-Rate Treatments in DOE's CBS Program

The CBS utilities evaluated a variety of time-based rates for their impact on customer acceptance, retention and response including ones that are driven by critical peak events and ones that are not. The primary objective of event-driven rates is to achieve reductions in peak (i.e., maximum) demand. Typically, utilities determine the need for critical peak events based on short-term system conditions, high forecasted wholesale market prices, or both. Participating customers receive notification of the events either on the day before or early on the critical peak event day.

The CBS utilities evaluated two primary types of event-driven rate programs: CPP and CPR. CPP designs involve increases in the price of electricity consumed during pre-determined hours (event period) on event days.[21] This higher price is overlaid onto the existing retail rate. CPR is similar to CPP except that customers are paid an incentive to reduce demand during the event period, relative to a baseline.[22]

The primary objective of non-event driven rate designs involves customers altering their consumption patterns more broadly, for example by shifting electricity consumption away from one part of the day to another. TOU rates are one of the most widely implemented types of non-event driven time-based rates and involve designs that charge customers for electricity usage based on the block of time it is consumed. Typically, this involves higher prices during a pre-determined set of

[20] Further details on the scopes of the studies can be found in "Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies" June 2013, Lawrence Berkeley National Laboratory.

[21] Most retail electric rates are designed to collect the same amount of revenue annually from the average customer in a class. Since CPP is designed to impose higher prices during a set number of critical peak events each year, the retail electric rate is lower on non-event days than the existing traditional utility tariff to offset the higher revenue collected during these events. This means customers have a risk for much higher bills when critical events are called (due to the higher price during events), but this would be offset by slightly lower bills the rest of the year.

[22] CPR is usually designed to overlay the incentive payment on the existing traditional utility tariff that is not changed. As such, the CPR incentive payments are typically drawn from levying slightly higher retail electric rates on all customers, not just those taking service under CPR. Because the rate increases associated with the incentive payments are spread across all customers in the class, they can be quite small on a per customer basis and are rarely noticed.

peak hours and lower prices during off-peak hours. TOU price schedules are fixed and pre-defined based on season, day of week, and time of day.

VPP, a hybrid of CPP and TOU, involves designs in which customers are charged based on the block of time electricity is consumed, but the price schedule differs based on existing power system conditions and/or wholesale market prices for that day. VPP rates are intended to encourage customers to broadly shift consumption away from peak periods, but to also accomplish greater peak demand reductions as needed when system conditions or market prices warrant.

In addition to rates, the CBS utilities also evaluated the role of customer systems including information and automated control technologies on customer acceptance, retention and response. Customer systems are thought to increase interest in acceptance of time-based rates, heighten interest in remaining on such rates, more easily respond to such rates and more generally enhance the ability of customers to manage electricity costs. Information technologies, like IHDs, more conveniently provide customers cost and energy use information, and control technologies, like PCTs, provide capabilities for customers to automate their responses to time-based rates.

The CBS utilities also evaluated different approaches to recruiting customers to participate and take service under the various time-based rates included in the studies. Many CBS utilities used an opt-in approach that sought volunteers to participate in the study. In a few cases, CBS utilities included an opt-out approach whereby customers were told they would be participating in the study unless they took action and declined.

Table 2 shows the rate and technology offerings being evaluated by the CBS utilities. The subsections that follow provide information about the scope and status of the ten utility studies.

Table 2. Scope of the Consumer Behavior Studies

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU Pricing		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

2.2 Cleveland Electric Illuminating Company (CEIC)

Overview. CEIC is part of FirstEnergy Services Corporation's SGIG Project which had a total budget of about $114 million (DOE's share of about $57 million) and included installation of about 34,000 smart meters, associated communications networks, and distribution automation equipment on about sixty feeders. CEIC's consumer behavior study's initial design involved about 5,000 residential customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns in response to CPR and use of IHDs and PCTs.

Treatments. Rate treatments included the implementation of a CPR that provides a payment to customers for reducing electric demand during declared critical peak events, while the price charged by CEIC for electricity consumed at other times stays at existing flat rates. Customers received day-ahead notification of critical peak events and could receive such notification up to 15 times per year. Technology treatments included IHDs and PCTs. The PCTs involved two treatment methods:

customer control and utility control. Because several treatment groups fell short of recruitment goals, CEIC chose to focus on a smaller number of treatments to obtain more precise impact estimates. The treatments involved a flat rate with CPR that included a $0.40 per kilowatt hour rebate and either (1) a four hour event duration that could be paired with an IHD or customer-controlled PCT, and (2) a four- or six-hour event duration that could be paired with a utility-controlled PCT.

Design. The study's experimental design involved a randomized encouragement design where customers were randomly assigned to either be offered a treatment or not offered a treatment. Data from customers who were offered a specific treatment but declined the offer were included in the study with data from the customers who were randomly assigned and not offered a treatment.

Status. CEIC completed its consumer behavior study. The recruitment effort fell short of its goals and so several of the experimental cells had to be dropped to maintain, to the degree possible, statistical power in the resulting load impact estimates. The interim evaluation on results from the summer of 2012 was published in May, 2013. The final evaluation covering activities during the summer of 2013 and 2014 was published in June, 2015. Based on the results, CEIC is considering expansion of CPR offerings in the future.

2.3 DTE Energy (DTE)

Overview. DTE's SGIG project had a total budget of about $168 million (DOE's share of about $84 million) and included a system wide roll-out of 725,000 smart meters and installation of distribution automation equipment on more than fifty feeders and ten substations. DTE's consumer behavior study's initial design involved more than 6,000 residential customers and focused on evaluating customer acceptance and response to various combinations of time-based rates (TOU with a CPP overlay) and IHDs and PCTs.

Treatments. Rate treatments included the implementation of a three-period TOU rate with a CPP overlay during the peak period (weekdays and non-holidays 3 – 7 p.m.). Critical peak events were announced with day-ahead notice to participating customers. Up to 20 critical peak events could be called each year. Control and information technology treatments included the deployment of IHDs and PCTs. In addition, all customers participating in the study received web portal access, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group. A simple random sample of AMI-metered residential customers in the service territory who meet certain eligibility criteria received an invitation to opt-in to the study where participating customers could receive one of several treatments, with the understanding that this treatment is limited in supply. Customers who opted-in were surveyed to ensure they met the eligibility criteria. Those who self-identified as having central air conditioning were randomly assigned either to a control group or to receive an offer to opt-in to one of four studies, each of which includes a TOU with CPP rate design and an offer of: no technology, an IHD only, a PCT only, or both a PCT and IHD. Those who self-identify as not having central air conditioning were randomly assigned either to a control group or to receive an offer to opt-in to one of two studies, each of which included a TOU-CPP rate design and an offer of either no technology or an IHD.

Status. DTE completed its consumer behavior study. The recruitment effort fell short of its goals and so several of the experimental cells had to be dropped or consolidated to maintain, to the degree possible, statistical power in the resulting load impact estimates. The interim evaluation on the results of critical peak event days called in August, 2012 and May, 2013 was published in January, 2014. The final evaluation covering additional critical peak event days during the summer of 2013 was published in August, 2014. Based on the results, DTE is offering the TOU with CPP rate designed for the study to its entire residential population on a voluntary basis.

2.4 Green Mountain Power (GMP)

Overview. GMP (along with VEC) is part of Vermont Transco's SGIG Project which had a total budget of about $138 million (DOE's share of about $69 million) and included deployment of more than 300,000 smart meters and installation of distribution automation equipment on more than forty feeders and ten substations. GMP's consumer behavior study's initial design involved more than 3,500 residential customers and focused on evaluating customer acceptance and response to different time-based rates coupled with information feedback treatments.

Treatments. GMP implemented CPR that provided a payment to customers for reducing electric demand during declared critical peak events, while the price charged for electricity during other times stayed at the customer's existing flat rate. GMP also implemented CPP overlay that slightly lowered the customer's existing standard flat rate but augmented it with a substantially higher price during declared critical peak events. Control and information technology treatments included the deployment of IHDs. This technology provided site-level electricity consumption information and customer notification of critical peak events. Customers also received notification by email, text, and voice message and had web portal access to interval meter data, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with denial of treatments for the control group and pre-recruitment assignments. AMI-enabled customers who met certain eligibility criteria were randomly assigned to either one of the two control groups (differing by customer's awareness about the study and critical peak events) or one of six treatment groups. Customers assigned to the flat rate with CPP treatment were required to agree to the rate change. Customers assigned to the flat rate with CPR treatment, or one of the control groups, were told of their assignment and could opt-out.

Status. GMP completed its consumer behavior study. The interim evaluation on the results of critical peak event days called in the summer and fall of 2012 was published In November, 2013. The final evaluation covering additional critical peak event days during the summer of 2013 was published in March, 2015. Based on the results, GMP is considering expansion of time-based rate offerings in the future.

2.5 Lakeland Electric (LE)

Overview. LE's SGIG Project had a total budget of about $35 million (DOE's share of about $15 million) and included deployment of more than 120,000 smart meters and supporting communications networks. LE's consumer behavior study's initial design involved more than 2,000 residential customers and focused on evaluating customer acceptance and response to a TOU rate, under both opt-in and opt-out enrollment approaches. This study focused primarily on evaluating the timing and magnitude of changes in residential customers' peak demand and energy usage patterns due to a seasonal three-period TOU rate.

Treatments. Rate treatments included a seasonal three-period TOU rate, where the definition of the peak period (weekdays and non-holidays) differed between summer (2 – 8 p.m. April – October) and winter (6 – 10 a.m. November – March) as did the definition of the shoulder period (summer: 12 Noon – 2 p.m. April – October; winter: 10 a.m. – 12 Noon and 7 – 10 p.m. November – March). All customers participating in the study received web portal access, customer support, and a variety of education materials, including a bill calculator.

Design. The study's experimental design involved a randomized controlled trial with delayed treatment for the control group. Opt-in and opt-out enrollment approaches were evaluated. For opt-in, the pool of eligible AMI-enabled residential customers in the service territory allocated for this part of the study received an invitation to join the study and receive the rate treatment, with the understanding that the application of this treatment could be delayed by one year. Opt-in customers were then randomly assigned to either receive the rate treatment or remain on their existing inclining block rate. Those who remained on the existing rate acted as a control group during 2012 and were then offered the new rate in 2013.

For opt-out, the pool of eligible AMI-enabled residential customers in the service territory received notification that they were chosen for a study and automatically received the rate treatment. Customers who did not opt-out were randomly assigned either to receive the rate treatment or to remain on their existing inclining block rate. Those who remained on their existing rate acted as a control group during 2012, and then were placed on the new rate in 2013.

Status. LE completed its consumer behavior study. The interim evaluation on the results from 2013 was published in February, 2015; and the final evaluation from 2014 activities was published in July, 2015. LE is currently offering the TOU rate designed for the study to its entire residential population.

2.6 Marblehead Municipal Light Department (MMLD)

Overview. MMLD's SGIG Project had a total budget of about $2.6 million (DOE's share of about $1.3 million) and included system wide deployment of about 10,000 smart meters and supporting communications networks. MMLD's consumer behavior study's initial design involved about 500 customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns from a flat rate with CPP overlay. MMLD was also interested in assessing residential customer acceptance and retention associated with this type of rate design.

Treatments. Rate treatments included the application of a flat rate with a CPP overlay with up to a six-hour period (12 – 6 p.m.) for critical peak events on non-holiday weekdays from June through August. Customers were notified of critical peak events, which were called in conjunction with ISO New England demand response events, by 5 p.m. the day before. Participants could receive notification for up to twelve critical peak events a year during the study. All customers participating in the study received web portal access, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with delayed treatment for the control group. Residential customers who met certain eligibility criteria received an invitation to opt-in to a study and receive the flat rate with CPP overlay treatment with the understanding that the application of this treatment could be delayed by one year. Customers who opted in were randomly assigned to either the rate treatment or their existing flat rate, which served as the control group for the first year of the study (summer, 2011). All participating customers received the rate treatment in the second year of the study (summer, 2012).

Status. MMLD completed its consumer behavior study. The interim evaluation on results from 2011 was published in May, 2012. The final evaluation covering 2012 was published in June, 2013. Following the study, MMLD decided not to expand deployment of time-based rates in spite of the sizable peak demand reductions they produced and indicated a preference for using direct load control programs to manage peak demands.

2.7 Minnesota Power (MP)

Overview. MP's SGIG Project had a total budget of about $3 million (DOE's share of about $1.5 million) and included deployment of about 8,000 smart meters, supporting communications networks, and installation of distribution automation equipment on one of its feeders. MP's consumer behavior study's initial design involved more than 4,500 residential customers and was implemented in two phases. Phase one evaluated customer acceptance and response to different forms of information feedback. Phase two evaluated these same issues but applied to a TOU rate with a CPP overlay.

Treatments. Phase one information feedback treatments included the development of a web-portal that provided randomly assigned customers with access to consumption data at varying levels of resolution and latency: (1) monthly aggregated data provided on a monthly basis (this was the control group); (2) daily aggregated data provided on a daily basis; or (3) hourly aggregated data provided on a daily basis (required installation of a smart meter). For Phase two MP implemented a two period TOU rate that augments its existing flat rate and includes a 13 hour peak period (i.e., 8 a.m. – 10 p.m.) each weekday. In addition, MP tested the effects of overlaying, during various blocks of the peak period, a higher price on critical peak event days. Customers received day-ahead notice of critical peak events, called when a major energy event was taking place in the Midwest Independent System Operator markets or on MP's system. Participants were to be exposed to no more than 160 hours of critical peak events per year of the study.

Design. Phase one of the study's experimental design involved a randomized controlled trial with denial of treatment for the control group. All residential customers in a given geographical area who met certain eligibility criteria received an invitation to opt-in to a study where participating customers can gain access to a web portal and receive one of three information feedback treatments. Customers who opted -in were surveyed, stratified, and randomly assigned to receive one of the three web portal information feedback treatments.

Because of recruitment shortfalls, MP decided to augment the study sample. All AMI-enabled residential customers who passed up the original offer to join Phase one participants were stratified and randomly assigned to receive one of the three information feedback treatments. These customers were notified of this opportunity and allowed to opt-out of the treatment by choosing to not access the information now made available to them via the web portal.

Phase two used a within-subjects design. All customers with installed smart meters, and others who met certain eligibility criteria and had a smart meter installed, received an invitation to opt-in to a study where participants received the rate treatment for one year.

Status. MP completed both Phase one and two of its study. The interim evaluation of results from Phase one (i.e., the summer of 2012) was published in March, 2014. MP completed Phase two in the fall of 2015 and is currently finalizing its final evaluation report. Customers on the Phase two rate were allowed to continue taking service on it until the utility while the utility considers whether or not to expand time-based rate offerings in the future to the entire residential population.

2.8 NV Energy (NVE) – Nevada Power (NVP) and Sierra Pacific Power (SPP)

Overview. NV Energy's SGIG Project had a total budget of about $278 million (DOE's share of about $139 million) and included deployment of about 1.2 million smart meters, supporting communications networks, and customer systems including PCTs and web portals. NV's consumer behavior study initial design involved more than 16,000 customers in two service territories: Nevada Power (NVP) (serves about 9,000 customers) in the southern part of the state, and SPP (serves about 7,000 customers) in the northern part of the state. NV Energy's consumer behavior study's focused on evaluating the timing and magnitude of changes in residential customer peak demand and energy usage patterns due to a seasonal multi-period TOU rate with a CPP overlay. NV was also interested in assessing residential customer acceptance, retention, and response associated with enabling technologies and energy education efforts.

Treatments. Rate treatments included the application of a multi-period TOU rate that used a five-hour peak period (2 – 7 p.m. at NVP; 1 – 6 p.m. at SPP) with rates that differ depending on the time of year (shoulder summer, June and September; core summer, July and August; and winter, October – May at NVP; and core summer, July – September and winter, October – June at SPP). NV Energy was augmenting the TOU rate with a substantially higher critical peak price (TOU-CPP) during a 4-hour weekday critical peak period in the summer (June – September 3 – 7 p.m. at NVP; July – September 2 – 6 p.m. at SPP). The CPP involved day-ahead notice to participating customers when forecasted temperatures, system demand, or wholesale market prices were expected to be very high and/or when system emergency conditions were anticipated. Study participants could be notified for no more than 18 critical peak events a year for NVP and 16 for SPP.

Control and information technology treatments included the deployment of PCTs. In addition, all customers participating in the study received web portal access. Education treatments augmented the customer web portal access with a curriculum designed to educate customers about energy, energy usage, energy costs and rates, and energy management. Study participants in NV Energy's enhanced education treatments were provided with information, examples, training, and feedback through a combination of written and online materials and experiences.

Design. The study's experimental design involved a randomized encouragement design. A stratified random sample of AMI-enabled customers in the service territory who met certain eligibility criteria were assigned to one of two pools of customers: one acted as the control group (i.e., remained on the existing flat rate without receiving an invitation for the time-based rate, technology or enhanced education) while the other received an invitation to opt-in to the study where participating customers received a single specific offer of treatment that was a combination of the rate, control/information technology, and/or education material. Offers to participate were randomized from the pool of eligible customers until samples size goals were achieved. Data from a sample of customers who were offered but declined the treatments were included in the study as was data from customers in the control group who were not offered the treatments.

Status. NV Energy's completed its consumer behavior study. Its interim evaluation extensively covered market research and load impact analysis results during the first year of the study (January, 2013 – February, 2014) and was published in August, 2015. The final evaluation focused more narrowly on major takeaways from all analysis efforts during the entirety of the study period (January, 2013 – February, 2015) and was published in March, 2016. The utility transitioned all of their study participants onto their existing TOU rate and extended an offer to participate in one of the utility's demand response programs.

2.9 Oklahoma Gas and Electric (OG&E)

Overview. OG&E's SGIG Project had a total budget of about $293 million (DOE's share of about $130 million) and included system wide deployment of about 790,000 smart meters, supporting communications networks, customer systems for about 48,000 customers, and installation of distribution automation equipment on about fifty feeders. OG&E's consumer behavior study's initial design involved about 5,000 residential, and more than 1,000 small commercial customers. OG&E's study centered on evaluating the timing and magnitude of changes in residential and small commercial customer peak demand and energy usage patterns from several types of time-based rates, IHDs, and PCTs.

Treatments. OG&E tested two rate designs: a two-period TOU rate with a variable peak pricing (VPP) component and a TOU with a CPP overlay. The VPP and TOU with CPP overlay used a five-hour peak period (2 – 7 p.m.) during non-holiday weekdays in the summer (June to September). The VPP peak period price was set to one of four different pre-determined levels with day-ahead (by 5 p.m.) notice. OG&E provided customers at least two hours' notice of critical peak events and each event lasted no more than eight hours. Critical peak events were called under conditions of high expected temperatures or system demand, or to avoid system emergencies.

Control and information technology treatments included the deployment of IHDs and PCTs. In addition, all customers participating in the first year of the study received web portal access, customer support and a variety of education materials. All customers in the service territory received access to the web portal during the second year of the study.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group and pre-recruitment assignment. AMI-enabled residential and small commercial customers who met certain eligibility criteria were stratified and randomly assigned to one of eight treatment groups, or to the control group. These customers received an invitation to opt-in to a study and receive one of several treatments, with the understanding that this treatment was limited in supply, but were not notified of their assignment at that time. Customers who opted-in were screened and surveyed for eligibility.

Status. OG&E completed its consumer behavior study. The interim evaluation covered activities during the summer of 2010 and was published in March, 2011. The final evaluation covers activities during the summer of 2011 and was published in August, 2012. Based on the results of the study, OG&E decided to roll-out the VPP rate programs and offer free PCTs to about 140,000 residential customers across its service territory.

2.10 Sacramento Municipal Utility District (SMUD)

Overview. SMUD's SGIG Project had a total budget of about $307 million (DOE's share of about $128,000 million) and included system wide deployment of more than 615,000 smart meters, supporting communications networks, customer systems for about 10,000 customers, and installation of distribution automation equipment on about 170 feeders. SMUD's consumer behavior study's initial design involved about 57,000 residential customers. SMUD's study focused on evaluating the timing and magnitude of changes in residential customer peak demand patterns due to various combinations of enabling technologies, different recruitment approaches (i.e., opt-in vs. opt-out), and several types of time-based rates.

Treatments. Rate treatments included the implementation of three time-based rate programs in effect from June through September: (1) a two-period TOU rate that included a three-hour peak period (4 - 7 p.m.) each non-holiday weekday; (2) a flat rate with CPP overlay; and (3) a TOU rate with a CPP overlay. Customers participating in any of the CPP overlay treatments received day-ahead notice of critical peak events that were called when wholesale market prices were expected to be very high and/or when system emergency conditions were anticipated. CPP participants could be notified of no more than 12 critical peak events during each year of the study.

Control and information technology treatments included deployment of IHDs. SMUD offered IHDs to all opt-out customers in any given treatment group and to more than half of the opt-in customers in the treatment group. All participating customers receive web portal access, customer support, and a variety of education materials.

Design. Due to the variety of treatments, the study included three different experimental designs: (1) randomized controlled trial with delayed treatment for the control group, (2) randomized encouragement design, and (3) within-subjects design. For all cases, AMI-enabled residential customers in SMUD's service territory were initially screened for eligibility and randomly assigned to one of the seven treatments or the control group.

For the two treatments included in the randomized controlled trial, recruit and delay, portion of the study, customers received an invitation to opt-in and receive an offer for a specific treatment. Upon agreeing to join the study, customers were told if they were to begin receiving the rate in the first year of the study or in the summer after the study was completed.

For two of the three treatments that were included in the randomized encouragement design, customers were told that they had been assigned to a treatment but had the ability to opt-out of this offer. Those who did not opt-out received the indicated treatment for the duration of the study. Those who did opt-out were included in the study but did not receive the indicated treatment.

For the two treatments that were included in the within-subject design, customers were told they had been assigned to either the flat rate with CPP overlay treatment or the TOU rate with CPP overlay treatment with technology. In the former case, customers only had the ability to opt-in to this specific treatment. In the latter case, customers only had the ability to opt-out of this specific treatment.

Status. SMUD completed its consumer behavior study. The interim evaluation covered activities during the summer of 2013 and was published in October, 2013. The final evaluation covered activities during the summer of 2014 and was published in September, 2014. Based on the results of their study, SMUD is consolidating all pricing tiers to produce a single flat rate for residential customers in 2018 and plans to transition all residential customers to a default TOU rate thereafter.

2.11 Vermont Electric Cooperative (VEC)

Overview. VEC (along with GMP) was part of Vermont Transco's SGIG Project which had a total budget of about $138 million (DOE's share of about $69 million) and included deployment of more than 300,000 smart meters and installation of distribution automation equipment on more than forty feeders and ten substations. VEC's consumer behavior study's initial design involved more than 3,500 residential customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns from a three-period TOU rate with variable peak prices, enhanced customer service-based information feedback, and enabling control and information technologies.

Treatments. Rate treatments included the application of a three-period TOU rate with a variable peak pricing (VPP) component, where the peak period price changed to reflect the average ISO New England day-ahead marginal locational price of electricity for those hours for the Vermont load zone. The definition of each period differed seasonally. During the summer (April – September), the peak period covered weekdays and non-holidays 11 – 5 p.m.; the shoulder period covered weekdays and non-holidays 5 – 10 p.m.; and the off-peak period covered all other hours. During the winter (October – March), the peak period covered weekdays and non-holidays 4 – 8 p.m.; the shoulder period covered weekdays and non-holidays 11 a.m. – 4 p.m. and 8 – 10 p.m.; and the off-peak period covered all other hours. Control and information technology treatments included the deployment of IHDs, proactive customer services, and home energy management systems.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group. A random sample of AMI-enabled residential customers in the service territory who met certain eligibility criteria received an invitation to opt-in to the study and receive one of several treatments, with the understanding that these treatments were limited in supply. Customers who opted-in were screened and surveyed for eligibility and randomly assigned to one of the three treatments or the control group. The study was originally designed to transition all treatment customers from their existing flat rate to VPP, while all control customers were to remain on their existing flat rate for the duration of the study.

However, due to attrition problems experienced in the first few months of the study that led to questions about the comparability of the customers in the control group to the remaining pool of treatment customers, VEC decided to alter the initial experimental design. To provide the best opportunity to estimate precise load impacts from VPP, VEC redesigned the study for the second year. This second part of study was designed such that all AMI-enabled residential customers in the service territory who met certain eligibility criteria received an invitation to opt-in and either receive the VPP treatment or remain on their flat rate (i.e., randomized controlled trial with denial of treatment for the control group).

Status. VEC completed its consumer behavior study. The interim evaluation covers activities during the summer of 2011 and is primarily a process evaluation because the difficulties with attrition and sample sizes precluded quantitative analysis. This was published in October, 2013. The final evaluation, published in September, 2015, covered the second part of the study and included results from June, 2013 through June, 2014. Future plans for implementation of time-based rates will be determined following completion of the study.

3. Recruitment Approaches

Social scientists have long recognized a behavioral phenomenon called the default effect or status quo bias –when facing choices that include default options, people are predisposed to accept the default over the other options offered. Historically, recruitment of residential customers to participate in time-based rates has almost exclusively involved opt-in approaches. This theory may help explain why utilities have been challenged for years in getting residential customers to widely accept voluntary time-based rate offers.

Today, with expanded deployment of AMI, increasing numbers of utilities and states are considering time-based rates as the default service option (opt-out). However, given limited industry experience with such recruitment approaches, especially at the residential level, there have been questions about the extent to which the default effect would apply to decisions about remaining on time-based electric rates after being placed on them.[23] Furthermore, various industry stakeholder groups have raised concerns about exposing vulnerable groups of customers (e.g., elderly and lower income) to time-based rates in a default environment.

Customer choices are key factors for the effectiveness of time-based rates in achieving their objective of reducing electricity demand during peak periods.[24] These choices include customer decisions to enroll and continue with new rates, their acceptance and use of various customer systems, such as IHDs and PCTs, and decisions to change their patterns of electricity consumption.

Two CBS utilities (SMUD and LE) have included both opt-in and opt-out recruitment approaches for treatment groups in their studies and have evaluated the impacts on enrollment, retention, and demand reductions. The other CBS utilities used opt-in recruitment approaches exclusively for all aspects of their studies.[25] In general, the CBS utilities were interested in evaluating these different enrollment approaches to answer several key questions about their efficacy, including:

- To what extent does the recruitment approach affect enrollment and retention rates?

[23] Baltimore Gas and Electric is one of the very few examples of a utility that has implemented an opt-out approach for its residential CPR program (Smart Energy Rewards). However, the CPR design results in no risk to customers who chose not to participate during declared critical events.

[24] When conducting experimental studies, the number of customers enrolled in programs needs to be large enough to produce statistically useful sample sizes. For larger-scale roll-outs, enrollment and retention levels need to be large enough to produce sufficient demand reductions to satisfy utility objectives for deferring capacity additions, or improving asset utilization.

[25] For further information on CBS enrollments see "Residential Customer Enrollment in Time-Based Rate and Enabling Technology Programs" LBNL 2013.

- What are some of the key lessons learned about customer engagement under the different recruitment approaches in the implementation of time-based rates?
- What types of bill management tools were employed and how does their application differ based on the recruitment approach?
- What are the effects on the magnitude and variability of demand reductions under different recruitment approaches?
- What are the costs and benefits of implementing time-based rates under different recruitment approaches, and under what conditions and circumstances are the offers cost-effective?
- What are the expected impacts on customer bills from implementing default time-based rates absent any load response, and is there any relationship between these expected bill impacts and participants' actual demand reductions, satisfaction and willingness to continue with the rate after the study ended?

3.1 Enrollment and Retention

If the default effect holds true, then opt-out recruitment efforts would result in much higher enrollment rates than opt-in approaches. Yet, utilities and others in the electric industry expect customers to drop out at higher rates than those recruited under opt-in approaches. Specifically, concerns have been raised that customers defaulted into time-based rates may not be aware of the consequences of their implicit acceptance of the time-based rate until they see their first bills. At that point, there is a concern that customers would be less likely to continue participating once they realize what they have been defaulted into, resulting in more drop outs, lower retention rates and lower customer satisfaction with the utility than under opt-in recruitment approaches.

Figures 2, 3a and 3b show the enrollment and retention rates (year 1 and year 2, respectively) from the SGIG consumer behavior studies by opt-in and opt-out recruitment approaches. Each bar in the figures represents a treatment group within a utility study. Figure 2 shows average opt-out recruitment approaches successfully enrolled approximately 6.2 times more participants than average opt-in recruitment approaches (93% vs. 15%) at 9 of the 10 CBS utilities.[26] This finding is generally consistent with default effect experiences from other industries, products, and services.

[26] Data from OG&E was not included in Figure 2 because comparable enrollment rates could not be determined from their mass media recruitment process. However, OG&E did collect data about customer retention by treatment group. As a result, Figures 3a and 3b include their results.

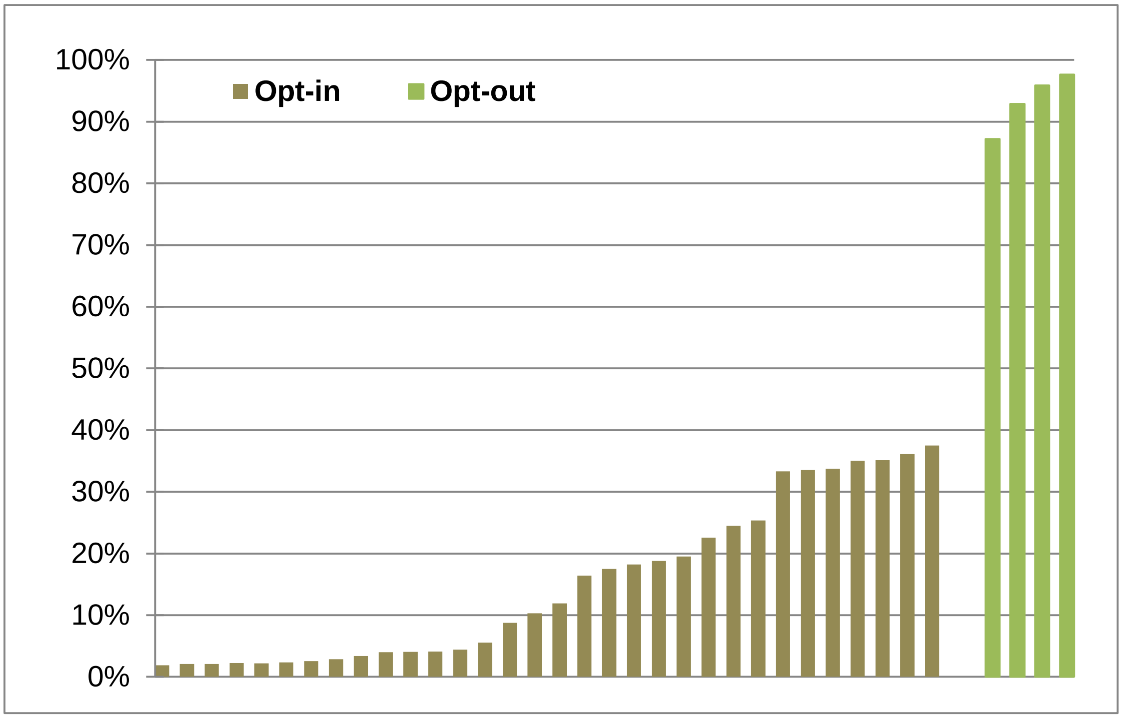


Figure 2. Enrollment Rates for Opt-in and Opt-out by Treatment Group.

Figures 3a and 3b show retention rates for year 1 (9 CBS utilities) and year 2 (5 CBS utilities),[27] respectively. Once customers joined the studies, the figures illustrate that opt-out recruitment did not result in large numbers of drop-outs during either year 1 or year 2 of the study period. In fact, retention rates were roughly the same for both opt-in and opt-out approaches, and didn't noticeably change from year 1 to year 2 of the study, as customers gained more experience with the rates. These results were contrary to the expectations of the CBS utilities.

[27] Not every CBS utility ran a two year study and some who did altered the design in the second year, in which case it was inappropriate to compare year 2 retention rates to year 1 retention rates.

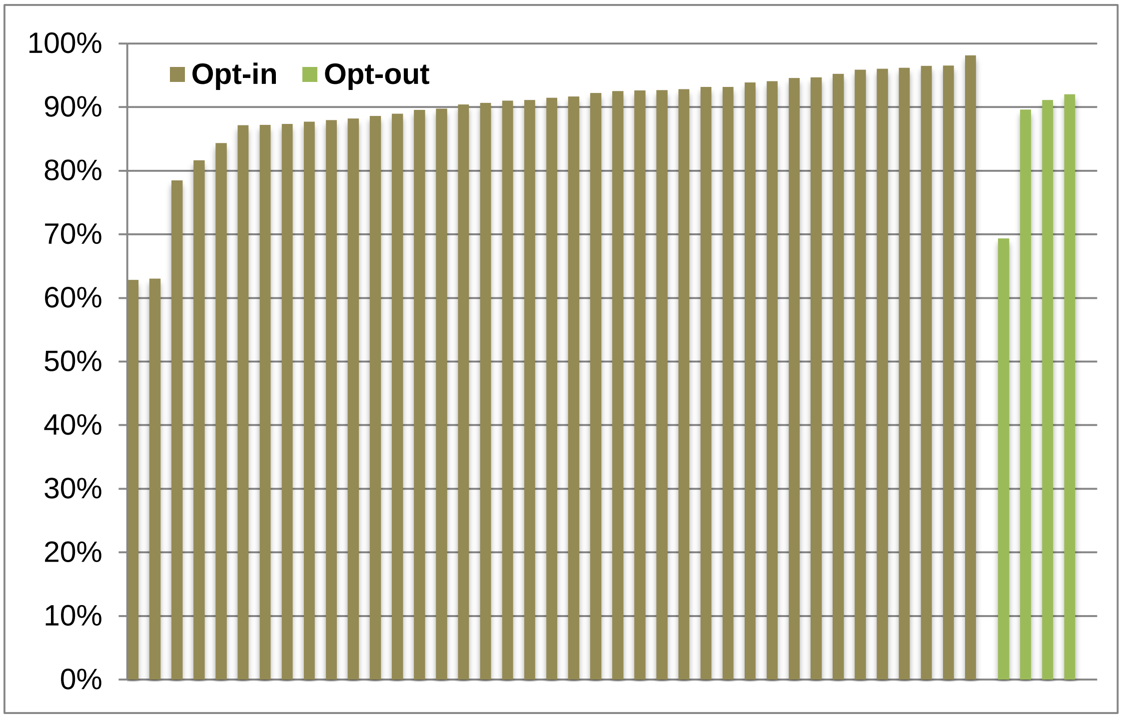


Figure 3a. Retention Rates for Opt-in and Opt-out by Treatment Group (Year 1 Only).

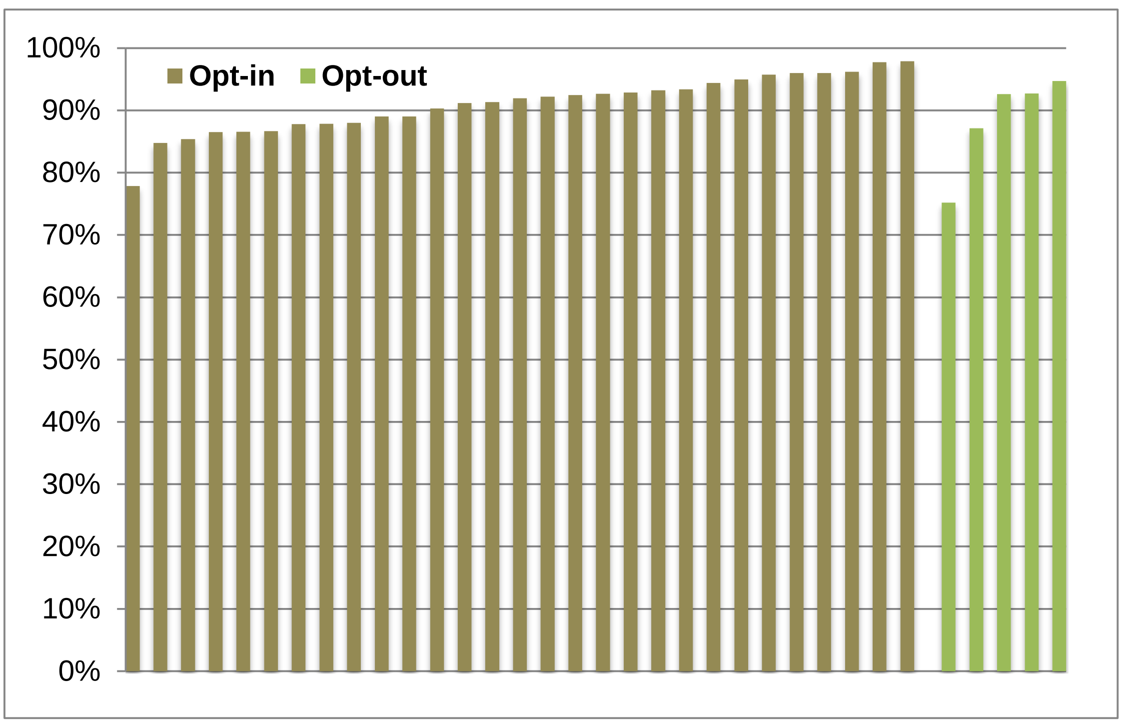


Figure 3b. Retention Rates for Opt-in and Opt-out by Treatment Group (Year 2 Only).

One of the CBS utilities (SMUD) included treatment groups to specifically evaluate the efficacy of opt-in and opt-out recruitment approaches. Figure 4 shows the effects of the different recruitment approaches on enrollment, retention, and dropout rates, and the results are consistent with the findings of the other CBS evaluations, which are shown in Figures 2, 3a and 3b.

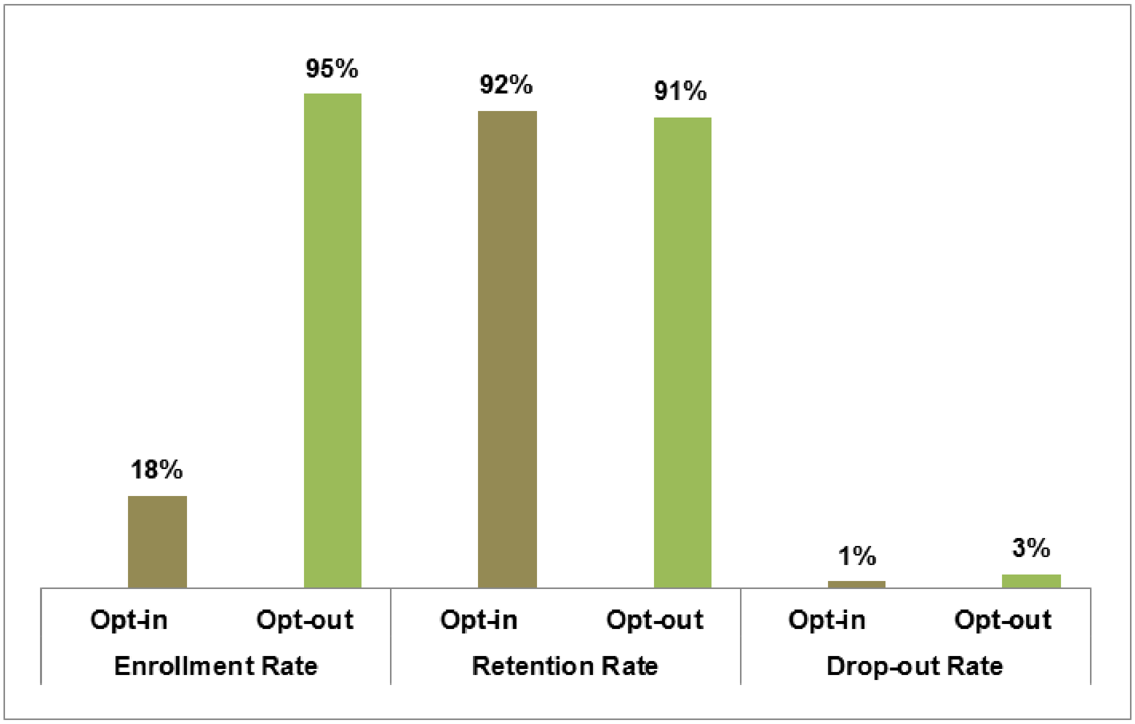


Figure 4. SMUD Enrollment, Retention, and Drop-out Rates for Opt-in and Opt-out.

3.2 Lessons Learned

Successful opt-in enrollments require extensive marketing and outreach to sufficiently raise customer awareness and successfully encourage participation in time-based rates. On the other hand, opt-out recruitment approaches do not require nearly the same level of market research to achieve high enrollment levels. However, marketing and outreach efforts are still required to make customers aware of the rate or program they are being placed into, the process they need to follow to opt-out and the actions they can take to manage the risks associated with the new rate or program. Customer engagement is essential for success under both opt-in and opt-out approaches.

In addition to opt-in and opt-out recruitment approaches, other activities implemented by the CBS utilities in two areas have particular bearing on customer enrollment and retention: (1) Education and Outreach and (2) Recruitment Strategies. Table 3 provides a summary of the lessons learned by the CBS utilities in these areas.[28]

Table 3. Summary of Lessons Learned for Opt-in Enrollments

Topics	Lessons Learned
Education and Outreach	Conduct General Customer Education
	Conduct Market Research
	Test Messages before Using Them
Recruitment Strategies	Conduct Soft Launches and Avoid Holiday Seasons
	Use Multiple Delivery Channels
	Set Realistic Expectations
	Avoid Confusing Messages

For education and outreach, which is especially important for opt-in recruitment approaches, the focus involves raising the knowledge and awareness of customers about new offerings. One challenge is that customers today have busy lifestyles and are bombarded with messages and sales pitches from many different vendors using all types of media, including newspapers, radio, television, phone lines, and the internet. The competition for a customer's attention is intense and the SGIG CBS utilities found they needed to sharper strategies and tactics to be effective.

One of the three key lessons learned for education and outreach involved needs for conducting more general customer education campaigns about utility opportunities for managing electricity demand, and customer opportunities for managing costs and bills. Methods used by CBS utilities for delivering education curricula were many and included public meetings involving small groups of customers in cities, towns, and communities; radio and newspaper advertisements; and web sites, social media and even smartphone apps.

Market research using customer surveys and focus groups was also found to be valuable in understanding customer needs and shaping effective messages. Yet, even with careful market research, the CBS utilities found it important to test messages and marketing materials before directly incorporating them into recruitment materials and sharing them widely with customers.

Successful recruitment strategies typically involve a variety of success factors including the quality and persuasiveness of invitation materials, clarity of messages, thoroughness in following up and

[28] For fuller analysis of lessons learned by CBS utilities in implementing time based rate programs see "Experiences from the Consumer Behavior Studies on Engaging Customers", U.S. DOE, September, 2014.

following through on customer questions and problems, and having the ability to anticipate and prevent common glitches from cascading into major problems.

One of the key lessons learned for effective recruitment strategies was to conduct soft launches[29] and avoid holiday seasons. Several of the CBS utilities found it important to allocate more time than was initially planned between soft and hard launches to implement fixes and make adjustments to messages. The CBS utilities also found that it is highly recommended to avoid soft and hard launches during the holiday season that stretches from mid-November through the first of the New Year. This mistake was made by at least one utility and recruitment rates were unacceptably low during that period.

The CBS utilities also found that use of both traditional (e.g., printed materials, such as letters and brochures, and telephone calls to homes and offices) and new methods (e.g., electronic materials delivered by emails, text messages to mobile phones, web sites, and social media) for delivery of messages was essential.

Setting realistic expectations for customers about the requirements of participation, performance of the devices, and potential bill savings was a key element of success as was the need to avoid the use of confusing messages.

3.3 Bill Management Tools

Several CBS utilities learned from market research that although environmental stewardship and increased reliability of the power system were important messages to promote customer participation in new rate offerings, customers were primarily interested in being able to better manage their electricity bills. Since most residential customers have only taken electric service under flat or inclining/declining block rate designs, bill management means that if they use less, then bills should go down. When time-based rates are introduced, the focus shifts away from using less overall, to shifting use from times when rates are high to times when they are lower. TOU rates, in particular, encourage customers to reduce consumption in high-priced peak periods and shift it to lower priced off-peak periods. CPP and CPR, on the other hand, encourage customers to reduce electricity use during specific hours on specific days of the year. These concepts were new to many customers and required new ways of thinking about electricity consumption and bill management.

[29] "Soft" launches refer to the release of a product, service, or program to a limited audience to gather information about usage and acceptance in the marketplace before making it generally available to a wider audience through a "hard" launch.

To help customers understand how their bills might be affected by particular time-based rate options, utilities have a variety of tools at their disposal. One is that utilities can provide web portals to customers. These internet sites allow customers to access and track their consumption and costs, often including information about how to manage both.

Another tool utilities can offer via the web portals is a bill calculator. This tool allows customers to estimate bill impacts under a variety of different rate designs. In addition, the tool allows customers to simulate how their bills might be affected from different actions (e.g., reduce X% of energy during a critical peak event or shift Y kWh from the peak to off-peak periods).

Once on a new time-based rate, utilities can also provide customers with bill comparisons (also known as shadow bills), either online or in paper form, to show how bills were affected by the new rates.[30] Lastly, utilities can provide bill guarantees[31] for customers taking service under new time-based rates.[32] The guarantees are intended to help customers adjust to new rates and protect them from adverse financial consequences associated with changing rates. Bill guarantees, however, are usually applied for limited periods of time (e.g., 6-12 months).[33]

Table 4 shows the types of bill management tools offered by the CBS utilities included in this report. The table also shows the diversity of tools offered to participating customers. For example, both LE and SMUD included opt-out recruitment approaches, but only LE provided a bill guarantee during a customer's first year on the rate. Only three utilities provided bill calculators to their customers. In general, the CBS utilities tried not to set specific expectations about bill savings during the enrollment phase of their studies. However, most of the studies did identify the opportunity to capture financial benefits (i.e., lower bills) as a reason to participate in the study.

[30] Because incentive-based programs involve a payment to a customer, the rebate is usually explicitly shown on the customer's bill. Thus, a bill comparison tool is not required to identify how a customer's financial position is affected by participation in such a program.

[31] Customers with bill guarantees usually pay the lower of two bills: the one they received under the new rate or the one they would have received under the old rate.

[32] Bill guarantees are generally not required with incentive-based programs unless they include non-performance penalty provisions.

[33] DOE strongly urged the CBS utilities to not apply a bill guarantee for the entire duration of the study, as this would not have been representative of the circumstances surrounding a broad roll-out of the rate offering to customers outside of a study setting.

Table 4. Types of Bill Management Tools					
CBS Utilities in this Report	**Web Portals**	**Bill Calculator**	**Bill Comparison**	**Bill Guarantee**	**Bill Guarantee Period**
DTE	●	●	-	-	-
FE	●	-	-	-	-
GMP	●	-	-	-	-
LE	●	-	●	●	12 months
MMLD	●	-	-	●	12 months
MNP	●	●	-	-	-
NVE	●	-	●	●	12 months
OG&E	●	-	●	●	12 months
SMUD	●	-	-	-	-
VEC	●	●	-	-	-

3.4 Demand Reductions

In addition to enrollment and retention rates, many in the electric power industry believe recruitment approaches can impact demand reductions on a per customer basis. The contention is that customers who opt-in are more likely to understand the rates they are enrolling in as well as what is expected of them to manage consumption and costs. As such, opt-in customers are generally expected to alter their consumption in some way in response to the rate. In contrast, customers who enroll under opt-out approaches may not always be making an affirmative decision: some may not have read the marketing material; some may have read it but did not understand it and never did anything to reject the offer; and others may have learned enough from the marketing material to know they were indifferent to the opportunity, thereby not eschewing it. These types of opt-out customers would not be expected to respond to the time-based rate opportunity even though they were technically enrolled.[34]

SMUD was interested in evaluating this issue and randomly assigned a subset of residential customers to different treatment groups with identical TOU rates but using different recruitment approaches (opt-in and opt-out). Figure 5 shows that per customer demand reductions for SMUD's opt-in customers in both year 1 and year 2 of their study (13% and 11% respectively) were about

[34] Commonwealth Edison's Customer Application Program (CAP) is one of the few examples in the electric industry to illustrate that this theory holds true in reality.

twice as large as they were for opt-out customers (6% for both year 1 and year 2).[35] This result supports the expectation that there are differences in motivation to reduce electricity demand for customers who volunteered to participate (opt-in) versus those placed on the rates by default (opt-out).

SMUD also evaluated identical CPP treatments that were offered to customers under both opt-in and opt-out recruitment approaches. Figure 6 shows that average demand reductions for SMUD opt-in customers over the two years the study was in effect were at least 50% higher than those measured for opt-out customers (13% vs. 12% in year 1 and 22% vs. 14% in year 2), likely due again to possible differences in motivation to reduce electricity demand for customers who opt-in, compared with those who could opt-out.

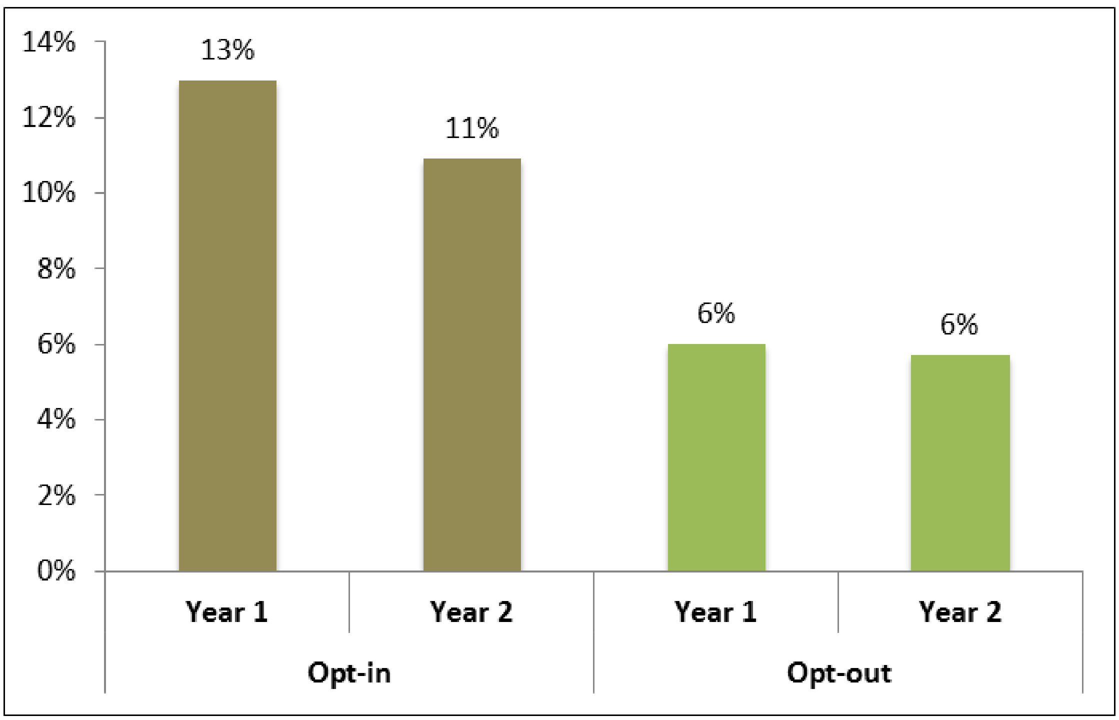


Figure 5. Percent Demand Reductions for SMUD Opt-in and Opt-out TOU Customers.

[35] The difference in these demand reduction estimates was found to be statistically significant, which means they are likely due to the rate and technology treatments rather than random factors. See pages 61 and 62 of the SMUD Interim Evaluation Report.

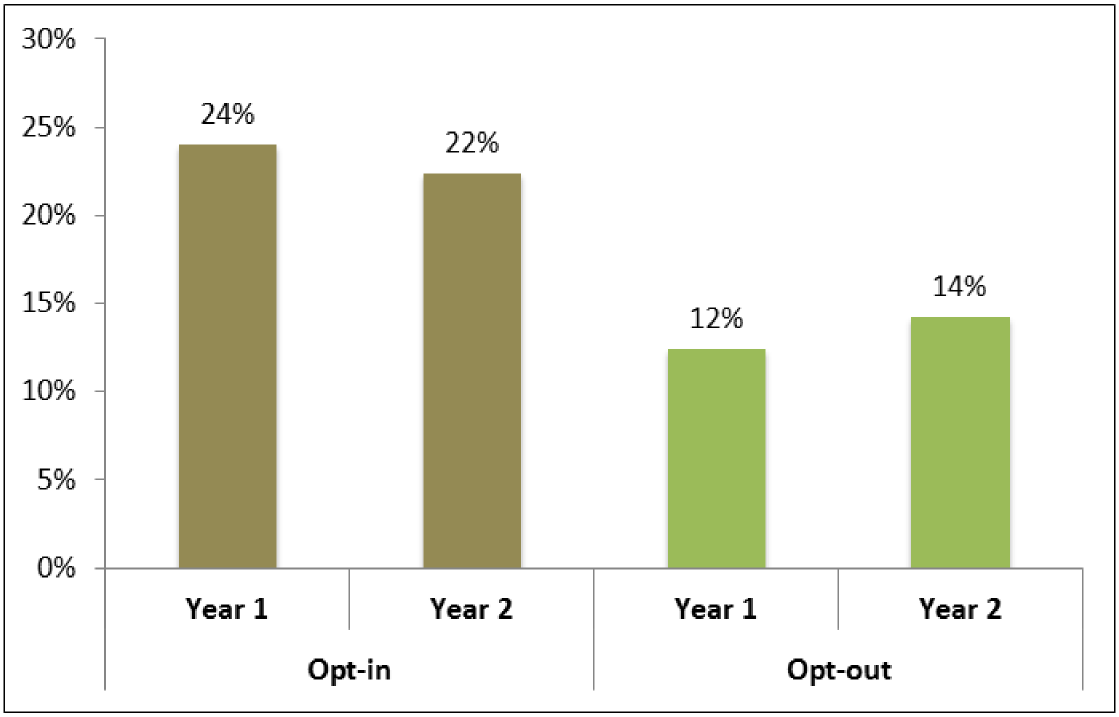


Figure 6. Percent Demand Reductions for SMUD Opt-in and Opt-out CPP Customers.

LE used a different approach to recruiting customers into their study than SMUD but did design a TOU rate that was identical for the opt-in and opt-out customers who took service under the rate in their study. Instead of initially assigning customers to receive an opt-in or opt-out enrollment solicitation, LE issued a general solicitation to its entire residential customer class to voluntarily (opt-in) participate in their TOU study. Of those who rejected this voluntary offer to participate, LE randomly selected a subset of these customers to default (opt-out) onto the TOU study.

This recruitment process may help explain the LE results for demand reductions. Opt-in customers reduced their peak period usage on average by approximately 8%. But the opt-out group did not reduce peak demand at all. Since the opt-out customers had either rejected the offer to voluntarily participate in the TOU rate, or had ignored the offer, one possible explanation is that they were far less engaged and hence less responsive than those who had volunteered.

3.5 Cost Effectiveness

Utility investments typically undergo cost-effectiveness screening by management, which serves as the foundation for regulatory filings to determine whether or not to authorize recovery of prudently incurred expenses. Utilities incur costs in the design and implementation of new time-based rates, including market research, recruitment campaigns, and sometimes some type of customer system such as IHDs and PCTs. The magnitude of recruitment efforts typically differs substantially between opt-in and opt-out approaches.

SMUD evaluated cost effectiveness to assess alternative rate and customer system (IHD) offers, and recruitment approaches, under different scenarios. As shown in Table 5, SMUD found positive benefit-cost[36] ratios for almost all of the scenario offers. However, opt-out recruitment had generally higher benefit-cost ratios for two reasons. First, they involved lower recruitment costs to achieve higher enrollment rates. Second, although each opt-out customer produced lower demand reductions in response to the time-based rates than each opt-in customer, in aggregate the opt-out customers produced much larger total demand reductions which resulted in higher benefits.

Table 5. SMUD Cost Effectiveness Analysis Results[37]

Recruitment Approach	Scenario Offer	Benefit-Cost Ratio
Opt-in	TOU, no IHD	1.19
	TOU, with IHD	0.74
	CPP, no IHD	2.05
	CPP, with IHD	1.30
Opt-Out	TOU, with IHD	2.04
	CPP, with IHD	2.22
	TOU-CPP, with IHD	2.49

3.6 Customer Bill Impacts

The results presented in this section so far show that the average residential customer defaulted onto a time-based rate generally appears willing to continue taking service on the rate and, in the case of SMUD, respond to the rate. However, this average result masks substantial diversity in underlying customer preferences and responses to new rates. In fact, one of the main concerns about defaulting all residential customers onto a time-based rate is that certain subpopulations will be adversely affected, especially financially.

[36] The SMUD benefit-cost results are based on a ten year net present value analysis with the benefits based on deferral value of capacity additions and avoided wholesale energy costs due to reduced loads during high cost periods or shifting usage from higher to lower cost periods. See Section 10.1 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

[37] Source: Table 10-5, page 114 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

Three sub-populations of customers can be defined to help clarify thinking about who might be at risk of being better off or worse off due to default time-based rates:

- **Never takers**: the set of customers that would not actively opt-in to voluntary time-based rate offers, and would actively opt-out when time-based rates are the default;
- **Always takers**: the set of customers that would actively opt-in to voluntary time-based rate offers and would not actively opt-out when time-based rates are the default; and
- **Complacents**: the set of customers who would not actively opt-in to voluntary time-based rate offers, but would not actively opt-out when time-based rates are the default.

The people who opt-in to a voluntary time-based rate would be likewise expected to not opt-out initially if defaulted onto the rate. Thus, how these ***Always Takers*** enroll in the time-based rate would likely not affect their satisfaction from taking service under it. In fact, they may benefit from a default rate in that they are automatically placed on the rate, and don't have to take the time to opt-in voluntarily.

In addition, there is a subpopulation of customers who prefer their existing rate over a time-based rate. These customers will not opt-in when solicited to voluntarily take up the time-based rate and will likewise opt-out if defaulted onto it. These ***Never Takers*** clearly express their preferences when presented with choices.

This leaves a third group of residential customers: the group that will not opt-in to a voluntary time-based rate but neither will they opt-out when TOU is made the default rate design. These ***Complacents*** seem willing to go along with the tariff that they are placed on by the utility.

Using information from SMUD's CBS study that explicitly included both voluntary and default enrollment of residential customers onto identically designed TOU rates, Figure 7 shows a breakout of the estimated proportions of these three subpopulations in SMUD's TOU treatments with an in-home display offer. In using SMUD data to analyze these subpopulations, it was necessary to assume that the group of Always Takers observed in the voluntary enrollment experimental design (19.5% of those solicited to opt-in) would represent the same proportion of, and act similarly to, those Always Takers who could not be directly identified in the default enrollment experimental design.[38]

[38] In other fields, this additional assumption is considered to typically be valid.

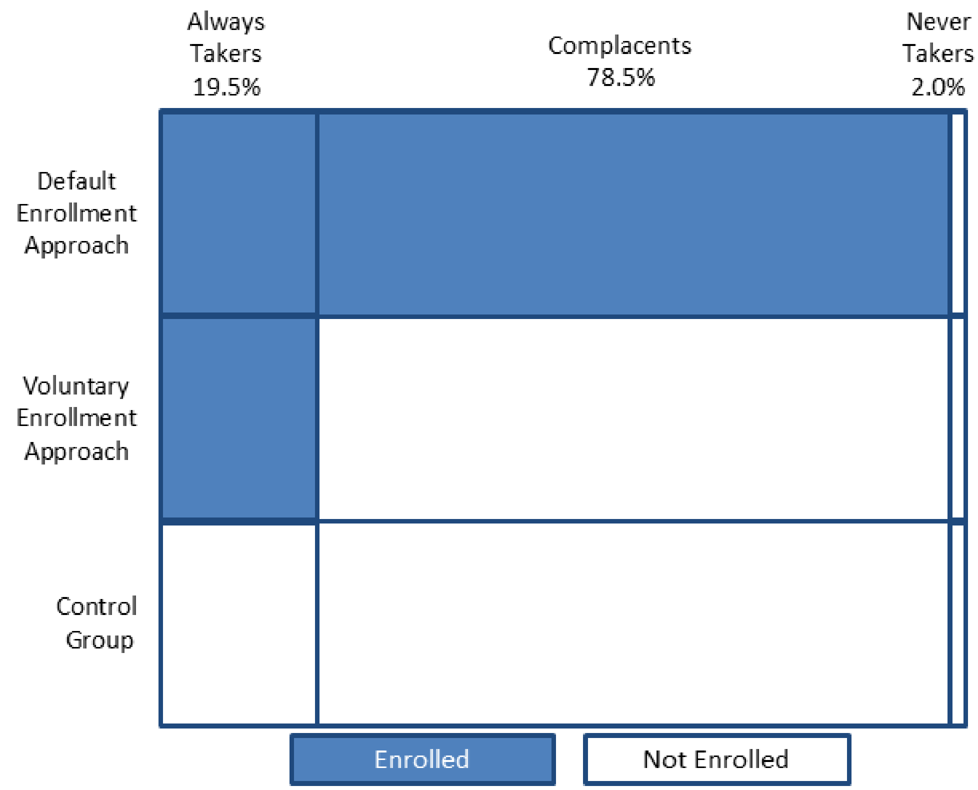


Figure 7. SMUD Residential Subpopulations for Analyzing Opt-in versus Opt-out Bill Impacts.

During the recruitment phase of the study, SMUD did not set explicit expectations with customers that each and every participant would save money by joining the study. Instead, SMUD's marketing material indicated the study's TOU rate created an opportunity for participating customers to save money by managing when they used electricity, not just how much they consumed. It is not clear if customers actually performed any calculations to assess their potential bill impacts from switching to the TOU rate, even without taking into account any change in their electricity consumption behavior.

An assessment of such predicted bill savings, based on an analysis of meter data from all of those who ultimately participated in the study under the default TOU rate, would have shown a distribution like the one in Figure 8.[39] About 22% of the Always Takers and 22% of the Complacent subpopulations, respectively, absent any response to the rate, were predicted to see +/- $5 impact on their bills over the entire four-month summer season the rate was in effect. If that range is

[39] Note that for the purposes of Figure 8 the distribution of predicted bill savings was truncated at +/-$100 per summer. There were 2 out of 12,925 customers with predicted losses greater than $100 and 22 out of 12,925 customers with predicted savings greater than $100.

expanded to +/- $10 for the full summer, 40% of Always Takers and 39% of Complacents would be predicted to see such bill impacts. Broadening the range even further to +/- $20 for the four summer months would capture a majority (66% and 67%, respectively) of both Complacent and Always Taker subpopulations. It is not clear what level of bill impact might have gotten SMUD's customers' attention to either accept or eschew participation in the study, but this similarity of impacts between the two subpopulation suggests that predicted bill impacts may not have been a key driver in the choice to participate in the study.

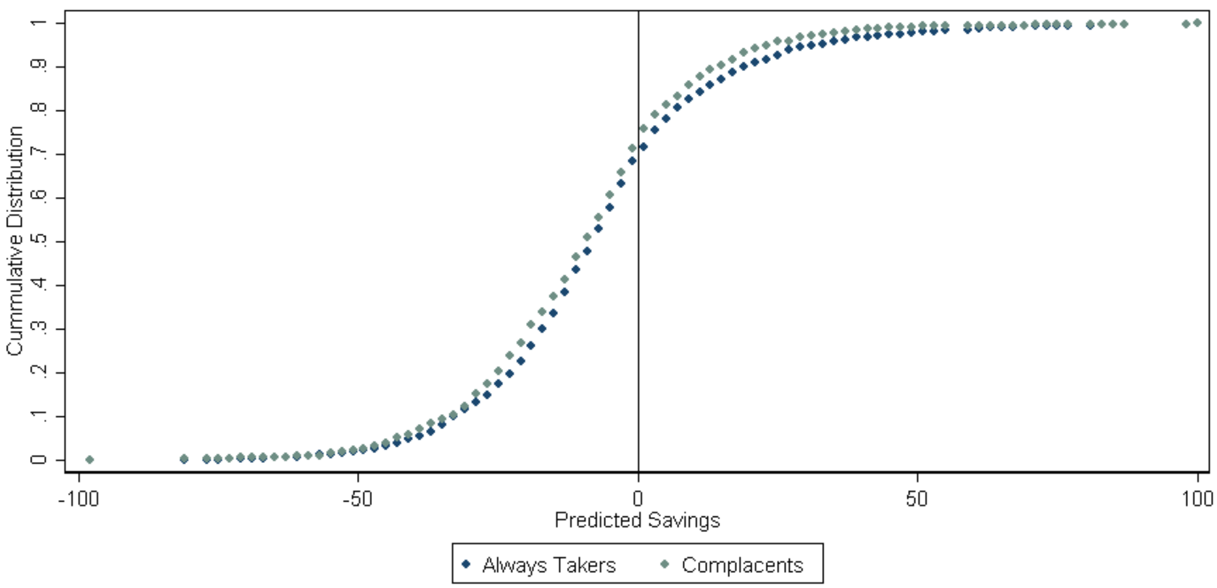


Figure 8. Distribution of Predicted Bill Savings by Customer Subpopulation.

Predicted bill impacts also have implications for the degree to which a participating customer would need to alter their electricity consumption patterns once exposed to TOU in order to achieve any positive bill savings. By breaking the Complacent and Always Taker subpopulations into smaller groups (i.e., quintiles of the predicted full summer bill savings), Figure 9 shows how the average customer in each of these subgroups reduced their peak period load during the study. Always Takers at the extremes of the predicted bill savings (i.e., those with the largest predicted bill losses or savings) exhibited a substantially larger load impact than those who might see more modest bill effects. Complacents exhibited a similar but less extreme version of this phenomenon. This suggests that for some share of both Complacent and Always Taker subpopulations, a large predicted bill impact, regardless of its direction, may increase the desire, willingness, or interest of a customer to manage their electricity consumption relative to one who anticipates that their current consumption patterns is less likely to substantively alter their bill on a TOU rate option.

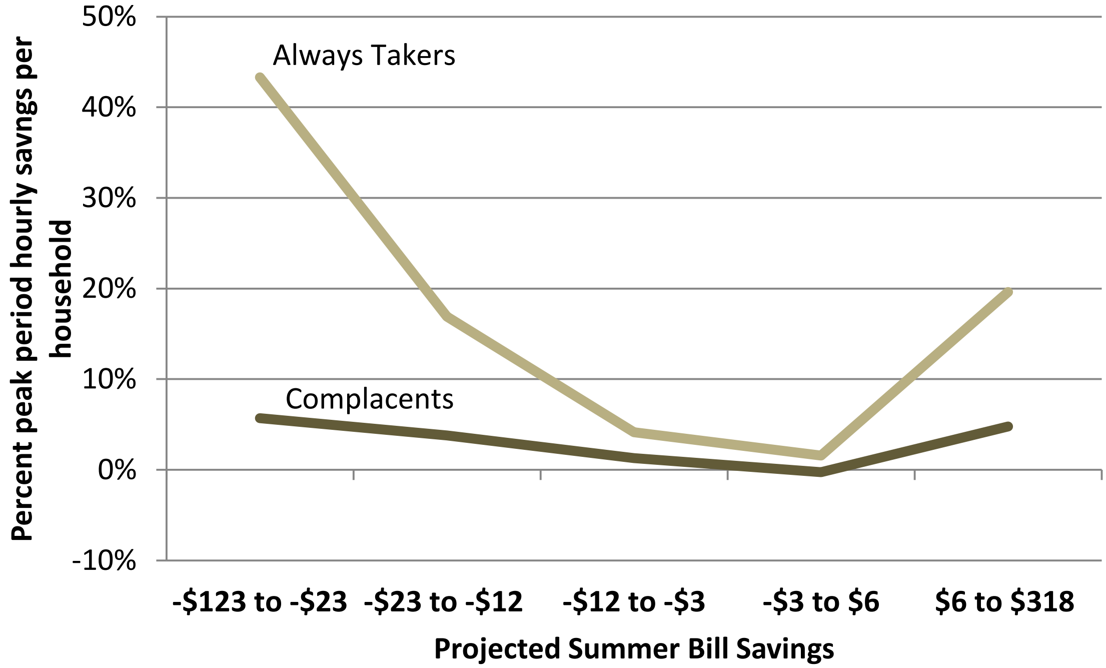


Figure 9.Peak Period Load Impacts by Quintile of Predicted Summer Bill Savings and Customer Subpopulation.

Lastly, the level of the predicted bill savings may also have implications for a participant's overall satisfaction with the default TOU rate, especially as it dictates the degree to which a customer might need to adjust their consumption to actually see a bill reduction. Based on survey responses, predicted monthly bill savings (as shown in Table 6), did not appear to be a major factor in how satisfied customers were with the default TOU rate once exposed to it. In fact, the survey respondents who were predicted to save the most by taking service under such a rate (i.e., greater than $20 for the entire summer) generally had lower satisfaction levels than those predicted to see their bills increase by $5 or more over the course of the summer (e.g., -$10 to -$5). Furthermore, the estimated level of satisfaction with the rate by Complacent survey respondents varied more widely across predicted bill savings and there appeared to be little relationship between the size of the bill impacts and the share of satisfied customers. However, there does appear to be a stronger direct relationship between the size of the predicted bill savings and the degree to which Complacent customers were interested in continuing with the rate. This finding reinforces the notion that a large share of the Complacent subpopulation were seemingly indifferent – they were reasonably satisfied with the rate, regardless of the level of bill savings they achieved, but those who likely lost the most during the study expressed an interest to not continue with the rate when given a direct opportunity to get off of it. In contrast, we see that the Always Takers who responded to the survey expressed lower levels of satisfaction with the default TOU rate as the size of the predicted bill savings increased. This result suggests that the increased effort by those Always Takers with the most to lose from participating in the study was an experience they actually found satisfying. Perhaps the more responding to the rate was required to capture bill savings, the more these customers were willing and interested in doing so. This heightened ability to manage and/or control their bills was seemingly viewed positively, especially for those with the most to gain from doing so.

Table 6. Share of Survey Responses by Subpopulation and Predicted Bill Savings

Predicted Summer Bill Savings ($)	Average Share of Survey Respondents Satisfied with the Existing Rate		Average Share of Survey Respondents Interested in Continuing with the Existing Rate	
	Always Takers	Complacents	Always Takers	Complacents
Less than - $20	94%	73%	96%	69%
-$20 to -$10	87%	92%	96%	89%
-$10 to -$5	89%	67%	92%	82%
-$5 to $5	82%	73%	94%	91%
$5 to $10	85%	100%	91%	100%
$10 to $20	72%	88%	88%	100%
Greater than $20	82%	53%	94%	92%

4. Prices versus Rebates

There is a theory in behavioral science called loss aversion, which states that when people are presented with choices that involve either avoiding a loss or acquiring a gain, the strong preference is to avoid the loss over acquiring the gain (e.g., the thought of losing $20 is more prominent than winning $20). For offers to enroll in CPP and CPR, customers are therefore expected to prefer CPR because there is no possibility of loss, whereas CPP carries the possibility of loss from higher bills.

However, once a customer is on the rate, CPP is expected to produce greater demand reductions than CPR. CPP is expected to be more motivating because customers face the punishment of a loss (through higher bills) if they do not respond, whereas response to CPR only has the benefit of a gain, and so is expected to be less motivating.

Because of the interest in finding the most efficient and cost-effective way to reduce demand during specific periods of time, several of the CBS utilities included evaluations of CPP, CPR or both in their studies. In general, the CBS utilities were interested in answering several key questions about their efficacy, including:

- How does the offer of CPP vs. CPR affect enrollment and retention rates?
- What are the effects on the magnitude and variability of demand reductions from CPP vs. CPR?

4.1 Enrollment and Retention

Utilities and others expect customers to be more likely to enroll in and remain on CPR than CPP. As discussed, the possibility of bill increase from non-performance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention.

GMP included both CPP and CPR treatments in their study and expected enrollment rates for CPR of around 80% versus 15% for CPP. GMP's recruitment experience was very different from this. As shown in Figure 11, GMP found that enrollment rates were about the same for both CPP and CPR. However, GMP did not expect differences in CPP and CPR retention rates, but actual experiences revealed slightly higher retention rates for CPR than CPP, also as shown in Figure 10.

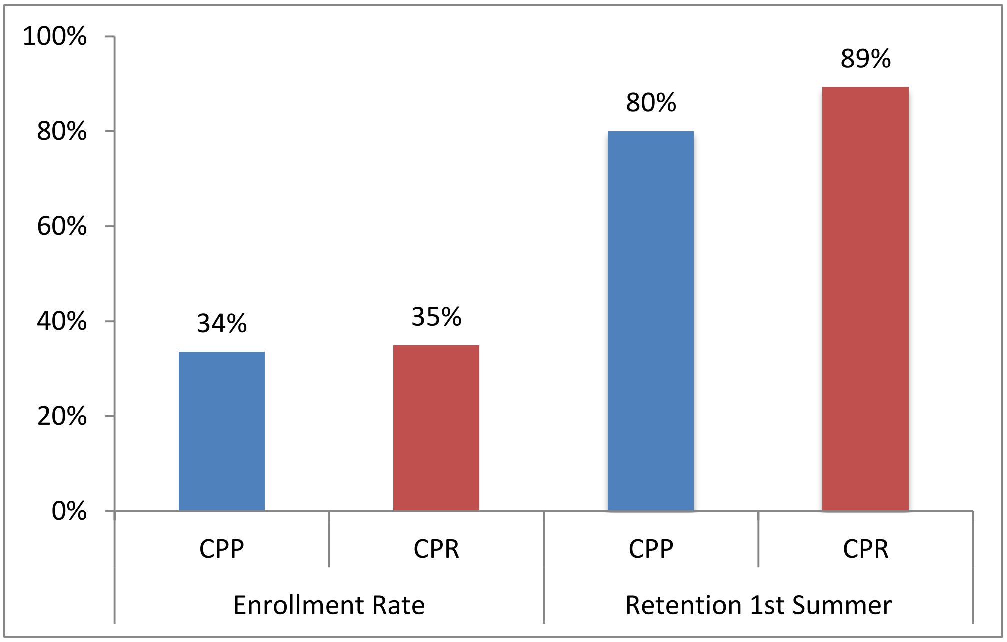


Figure 10. GMP Enrollment and Retention Rates over Time.

4.3 Demand Reductions

Because of the lower potential for higher bills associated with non-response during critical events, many of the CBS utilities expected smaller peak demand reductions for CPR than for CPP. Figure 11 shows average demand reduction during critical peak events across all CBS customers participating in CPP and CPR treatments, including both customers with and without technologies such as IHDs and PCTs. As shown, customers on CPP rates reduced demand by more than twice as much, on average, during critical peak events as those on CPR (25% vs. 11%). This result supports the expectation that demand reductions on a per customer basis under CPP would be greater than those under CPR.

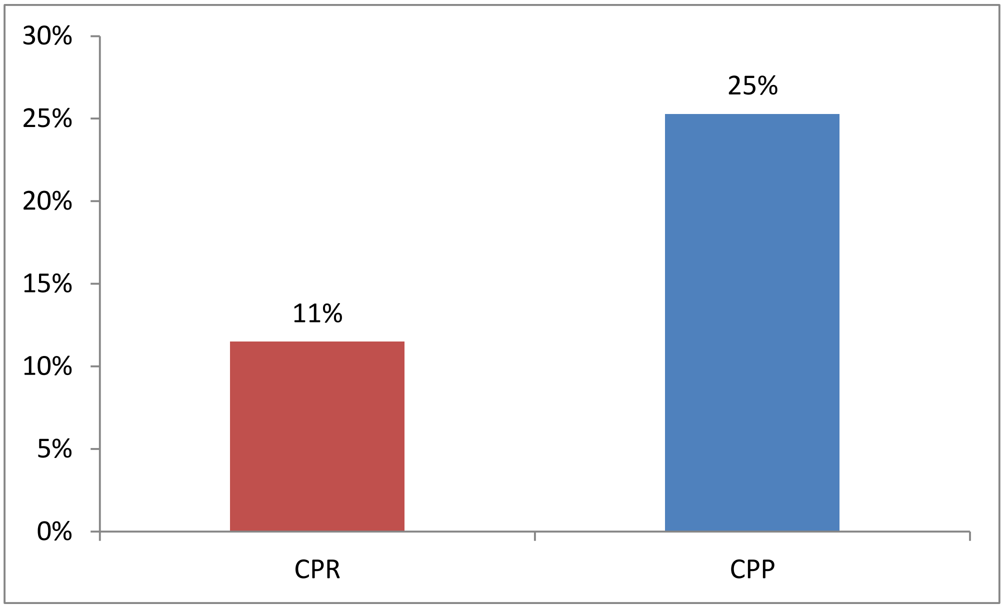


Figure 11. Average Percent Demand Reductions for CBS Customers on CPR and CPP.

However, demand reductions for both CPP and CPR were affected by the use of PCTs. These devices can be programmed to automatically control air conditioners and raise thermostat set points during critical peak events when prices are high (CPP), or when incentives are available (CPR). Each marker in Figure 12 represents one of 72 treatment groups from 8 utilities.

While Figure 11 shows CPR customers with lower demand reductions than CPP customers on average overall, Figure 12 shows that demand reductions for CPP and CPR substantially increased on average for customers with PCTs (15 and 20 percentage points, respectively). This suggests that regardless of the financial incentive to respond (i.e., acquiring a gain via a rebate or avoiding a loss via pricing), PCTs can be an effective tool to mitigate a customer's loss aversion by allowing them to automate their response during the critical peak events.

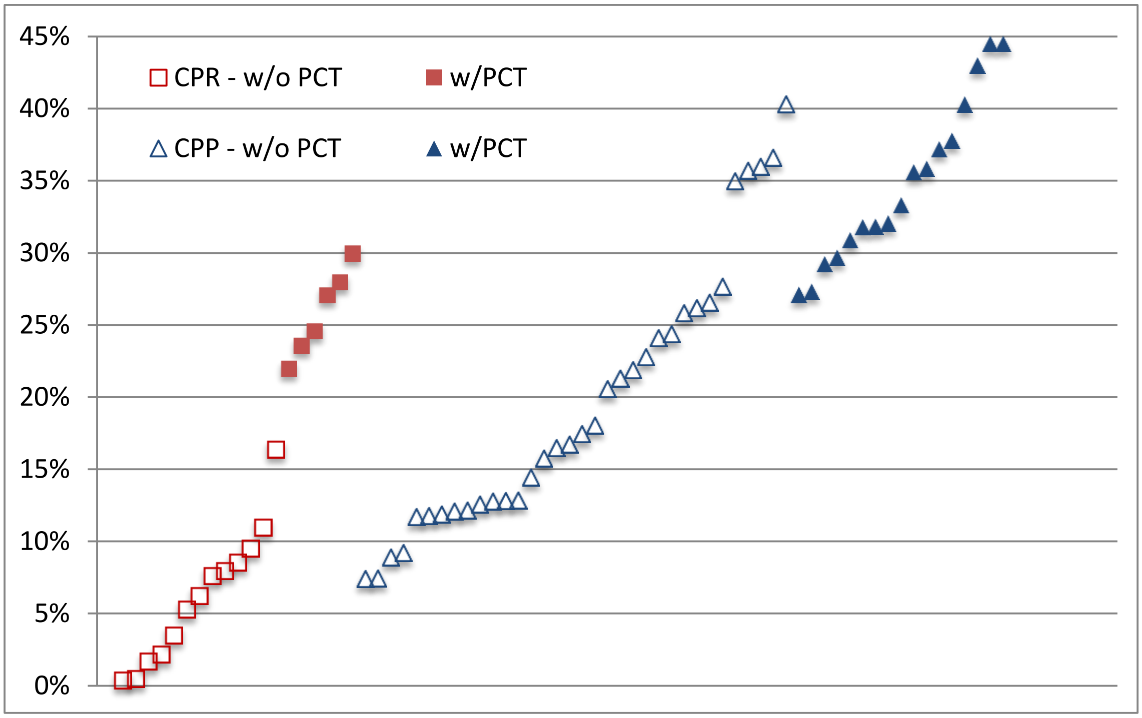


Figure 12. Average Percent Demand Reductions for Customers on CPP and CPR with and without PCTs by Treatment Group.

In addition to the magnitude of the response, system operators are concerned about the reliability and predictability of demand reductions during critical events, including possible differences between CPR and CPP. Figure 13 shows the distribution of average event demand reductions across all critical peak events for each non-PCT CPP or CPR treatment offered by GMP and OG&E, and the single CPP treatment offered by SMUD.[40] While the variability in average demand reductions across events is less for CPP than it is for CPR, demand reductions are still variable in both cases.

Using the New York Independent System Operator's definition of performance factor for its Special Case Resource program[41] (i.e., demand response resources providing capacity service during declared system reliability emergencies), customers on CPP would have had their claimed capacity capability (i.e., overall event average demand reductions) derated (or lowered) by 10% to account for variable performance. In contrast, customers on CPR would have had their claimed capacity capability reduced by three times that amount (30%).

[40] SMUD only provided event-by-event demand reductions for a single treatment cell in their evaluation reports.

[41] New York Independent System Operator (2014). Manual 4 – Installed Capacity Manual. NYISO: Rensselaer, NY. October.

This variability may be an important consideration for utilities seeking to have these resources provide capacity credits cost-effectively, and for system operators to use these rates and programs to help ensure resource adequacy.

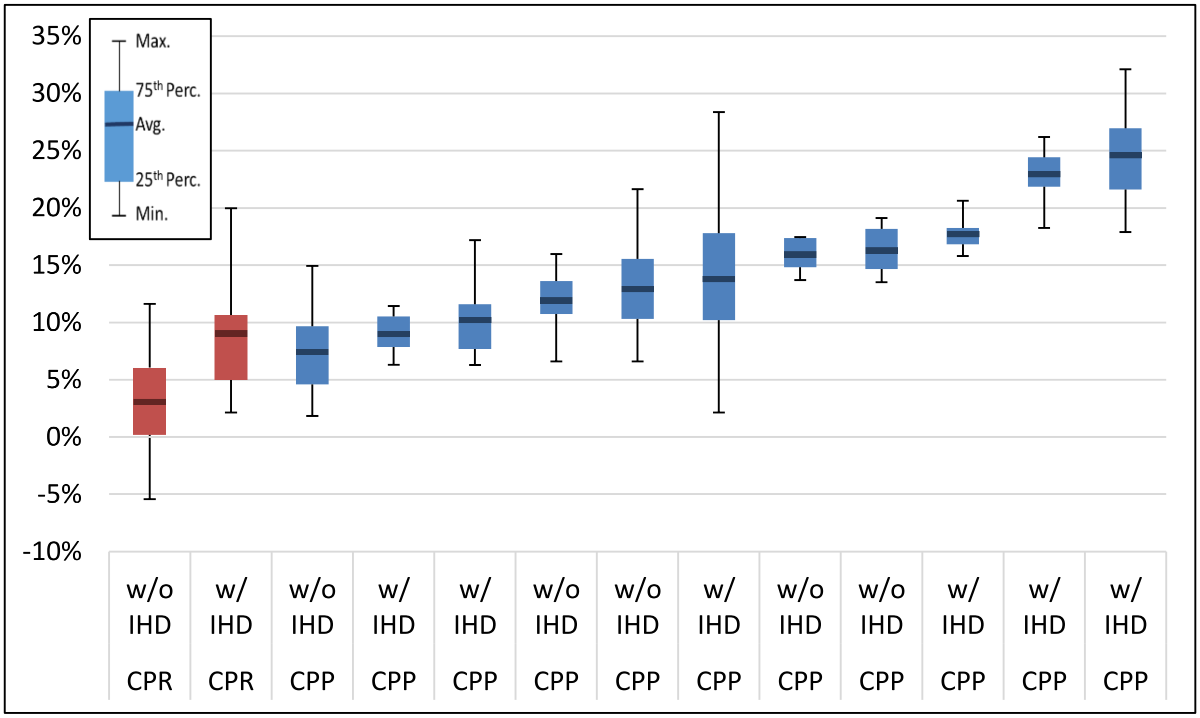


Figure 13. Variability of Per Customer Percent Demand Reductions across All Events for Customers on CPR and CPP (without PCTs) by Treatment Group.

5. Customer Information Technologies

Enabled by AMI, customer information systems are a category of devices that provide near real-time information to customers about their electricity consumption and costs. The category includes IHDs, which are small video screens that receive consumption and cost information from utilities. Several CBS utilities evaluated IHDs directly in their studies. The category also includes web portals which typically provide dashboards and analysis tools for customers to use via the internet in managing their consumption and costs. All of the CBS utilities offered web portals to customers, but none established treatment and control groups to evaluate their efficacy on customer enrollment, retention, or response.

Customer information technologies such as IHDs and web portals provide ways of raising customer awareness of usage levels, consumption patterns, electricity prices, and costs. By bringing attention to the prices and usage patterns, which otherwise might not be readily available or rarely accessed, utilities create opportunities for customers to better understand how their usage directly affects their bills. By having this information, it is expected that customers will have better capabilities for understanding and responding to time-based rates. However, when IHDs are offered by utilities to customers for free (which is frequently done as a means to attract participants and improve demand responses) program implementation costs increase, so it is important to understand if the benefits outweigh the costs of the technologies.

Many of these types of customer technologies are relatively new to the marketplace. Protocols and standards for transmitting price and consumption information to these devices are still evolving. Utilities have low levels of experience integrating the technologies and data streams into back-office systems and customers are unfamiliar with installation and operation procedures. As a result of these and other factors there are often bugs to address and learning curves to climb before performance can be fully evaluated. There are ample opportunities in this area for innovation and experimentation and many vendors are actively exploring new technologies, including software applications for mobile phones and portable computers.

Because of the potential advantages, several of the CBS utilities included evaluations of IHDs in their studies and addressed several key questions about their efficacy, including:

- What are some of the key lessons learned about IHDs in the implementation of time-based rates and incentive-based programs?
- To what extent do offers of IHDs affect enrollment and retention rates?

- To what extent do customers use offered IHDs, and what are the effects on the magnitude and variability of demand reductions?
- What are the costs and benefits of including IHDs and under what conditions and circumstances are the offers cost-effective?

5.1 Enrollment and Retention

Figures 14, 15, and 16 show the results for IHD offers on enrollment and retention rates for three CBS utilities – DTE, GMP, and SMUD. In all cases, the differences in enrollment and retention rates with and without offers of IHDs were small and did not appear to boost enrollment or retention rates, as many in industry expected they would.

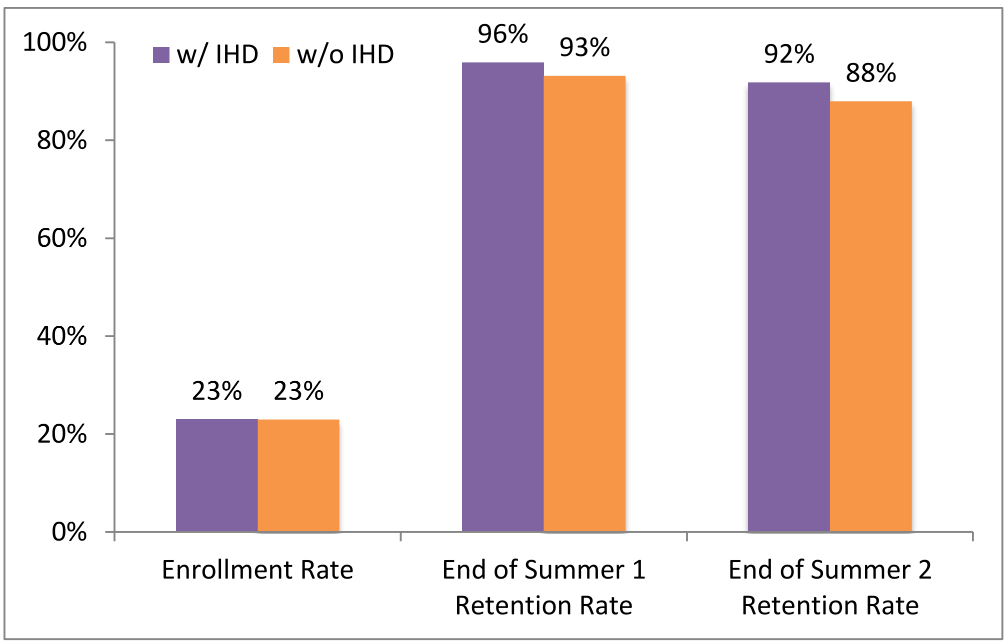


Figure 14. DTE Enrollment and Retention Rates with and without IHDs.

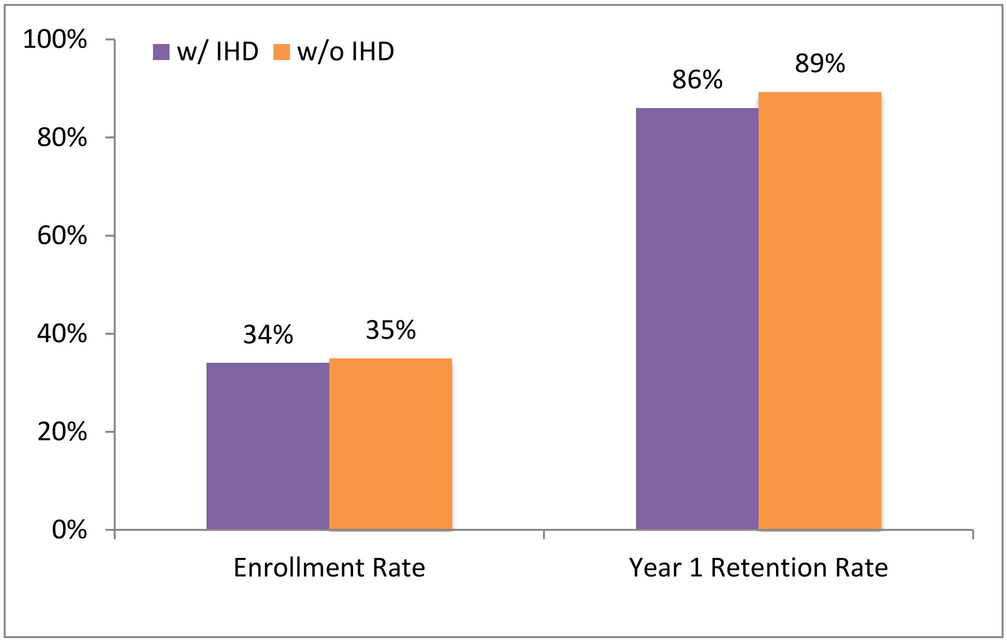


Figure 15. GMP Enrollment and Retention Rates with and without IHDs.

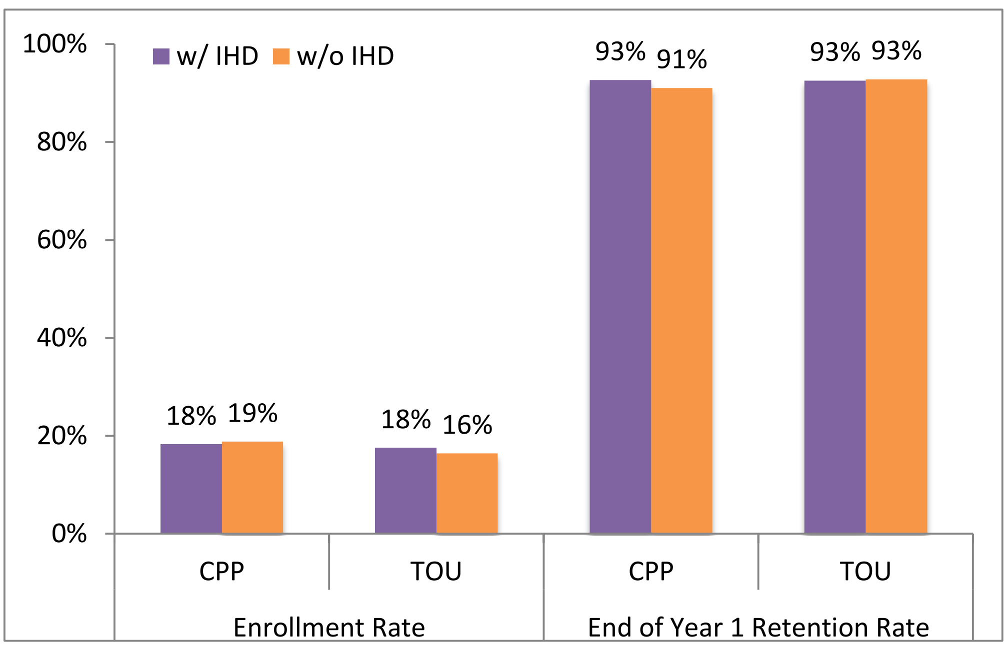


Figure 16. SMUD Enrollment and Retention Rates with and without IHDs.

5.2 Lessons Learned

Several of the CBS utilities encountered implementation problems with IHDs. Numerous instances were reported by most of the CBS utilities of equipment capabilities falling short of vendor statements and marketing material claims. For example, several utilities reported problems in getting timely servicing from vendors who had promised one level of support but delivered something less. In at least one of the studies, the vendor announced they were no longer supporting the device midway through the study and well after the devices had been installed.

SMUD tracked the connectivity of IHDs to better understand the degree to which customers were using them. Table 7 shows that less than 20% of the customers who received an IHD actually had it connected to the utility's system all the time. Instead, the majority of participants in three of the five treatment groups who received an IHD never actually turned it on and connected it to the utility's system.

Table 7: SMUD Connectivity Rates of IHDs

Treatment Group	% Connected All the Time	% Connected Some of the Time	% Never Connected
Opt-in CPP, IHD Offer	11.6%	27.4%	61.0%
Opt-in TOU, IHD Offer	11.6%	22.8%	65.6%
Default TOU-CPP, IHD Offer	18.8%	39.3%	42.0%
Default CPP, IHD Offer	14.3%	42.9%	42.9%
Default TOU, IHD Offer	18.2%	23.1%	58.7%

As a result of these experiences, several of the CBS utilities reported that:

- It is necessary to dedicate time and resources to conduct tests to ensure the equipment does what it is supposed to do, it can work with the other back office utility systems, and that servicing happens quickly and easily.
- In working with vendors, properly worded contract provisions can provide mechanisms for addressing equipment/vendor problems.
- One of the utilities tackled equipment servicing without using vendors by keeping such activities in house and said it was helpful in avoiding problems and customer frustrations with non-functional or poorly functioning equipment.
- Although customers may explicitly agree to receive these devices, some may not necessarily use them.

5.3 Demand Reductions

SMUD evaluated the effects of IHDs on demand reductions under TOU and CPP rate designs for opt-in enrollment approaches. Figures 17 and 18 show that the derived demand reductions for CPP and TOU customers were generally higher for those with IHDs than for those without IHDs, during both years of the study. However, as SMUD's evaluation report points out, these results do not suggest that the difference in the demand reduction estimates can be attributed to the effects of IHDs. According to the final evaluation report, once pre-treatment differences between the sample of customers in the two groups (with and without IHDs) are taken into account, there is no measurable effect of IHDs on demand reductions.

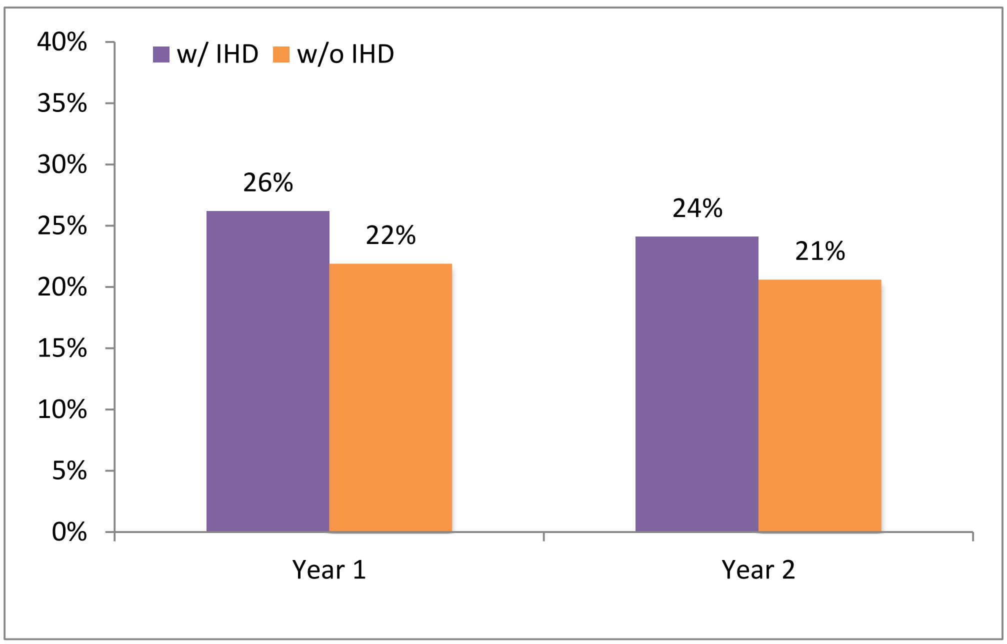


Figure 17. Average Percent Demand Reductions for SMUD's Opt-in CPP Customers with and without IHDs by Year.

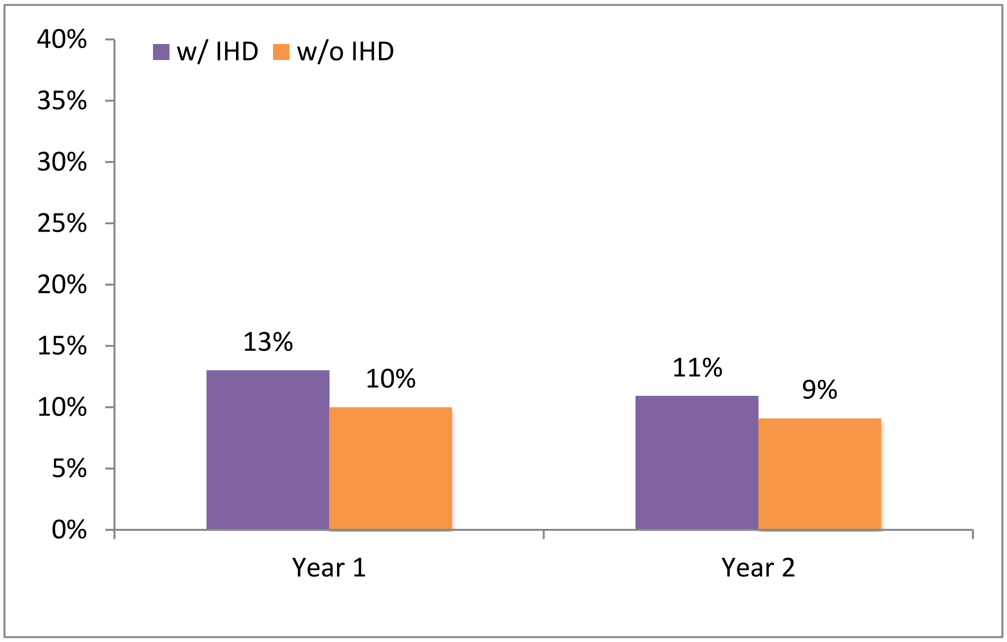


Figure 18. Average Percent Demand Reductions for SMUD's Opt-in TOU Customers with and without IHDs by Year.

In addition to understanding if IHDs can affect average levels of demand reductions, many are interested in knowing the degree to which IHDs may affect the variability of demand reductions over time. If by providing more information to customers about consumption and costs, IHDs were able to reduce variability, they would improve cost-effectiveness by increasing the levels of confidence and certainty for grid operators in the magnitude of demand reductions that involve offers of IHDs.

The data shown in Figure 19 reflect the variability of demand reductions on a per event basis from 3 CBS utilities and 13 treatment groups. On average, the level of variability of demand reductions is largely unaffected by the offer of an IHD making the results generally inconclusive with respect to the capabilities of IHDs to reduce the variability of demand reductions. Further study and analysis is needed to fully assess the role of IHDs to affect the variability of demand reductions for time-based rates and incentive–based programs.

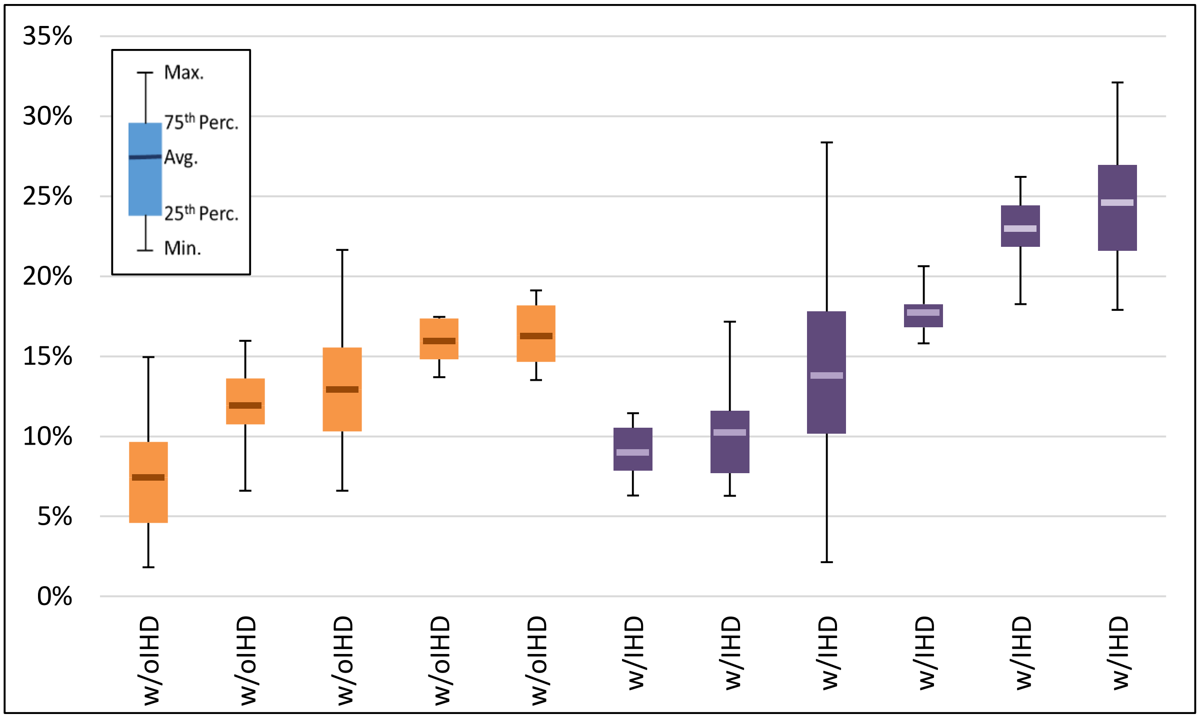


Figure 19. Variability of Per Customer Percent Demand Reductions for CPP Treatment Groups with and without IHDs by Treatment Group.

5.4 Cost Effectiveness

SMUD conducted cost-effectiveness analysis for a variety of rate offerings (TOU and CPP) with and without IHD offers. The benefit-cost ratios shown in Table 8 are consistent with the Total Resource Cost test as defined in the California Standard Practice Manual[42] and assume a 10-year time-frame that begins in 2018 and a nominal discount rate of 7.1%.

For both TOU and CPP, SMUD found higher benefit-cost ratios for scenarios without IHDs than for those with IHDs. While SMUD found that IHDs were correlated with slightly higher retention rates (1-4 percentage points) and boosted the magnitude of demand reductions by 2-4 percentage points, the costs of the devices were large enough to offset the majority of the additional benefits the IHDs generated. In the case of TOU rates, the offer of an IHD led to a result that was not cost-effective.

[42] CPUC, "California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects" October, 2001.

Table 8. SMUD Cost Effectiveness Analysis Results for IHDs		
Recruitment Approach	**Scenario Offer**	**Benefit-Cost Ratio**
Opt-in	TOU, no IHD	1.19
	TOU, with IHD	0.74
	CPP, no IHD	2.05
	CPP, with IHD	1.30

6. Customer Automated Control Technologies

Customer automated control technologies are a category of devices that enable utilities and/or customers to automate responses to price or control signals for the purpose of altering the timing and level of electricity consumption. For residential customers, these technologies include PCTs and load controllers for air conditioners, water heaters, and swimming pool pumps. These types of technologies, especially load controllers, have been used for decades by utilities, and there is relatively more experience with their deployment than with newer customer information technologies. Several CBS utilities conducted evaluations of the efficacy of PCTs.

Conceptually, control technologies lower the transaction costs associated with responding to prices and critical peak events by making it easier for customers to reduce consumption and thereby increase the size of overall demand reductions. PCTs simplify the process of responding to critical events and/or higher priced periods by controlling air conditioner thermostat settings. However, as with IHDs, utility offers of free PCTs cause implementation costs to increase, so it is important to understand if the value of the additional demand reductions outweighs the costs of the technologies.

Because of the potential advantages several of the CBS utilities included evaluations of PCTs in their studies and addressed several key questions about their efficacy, including:

- What are some of the key lessons learned about PCTs in the implementation of time-based rates and incentive-based programs?
- To what extent do offers of PCTs affect enrollment and retention rates?
- To what extent do customers use offered PCTs, and what are the effects on the magnitude and variability of demand reductions?
- What are the costs and benefits of including PCTs and under what conditions and circumstances are the offers cost-effective?

6.1 Enrollment and Retention

Because of the way the CBS utilities designed the PCT treatments, it was not possible to assess the impacts on enrollment rates.[43] However, analysis of retention rates shows little or no impacts from

[43] Since many of the CBS utilities did not have accurate information about their residential customers' ownership of central air conditioning, it was only at the point when a customer responded to the offer to participate did the utility

PCT offers, as shown in Figures 20a and 20b, which runs counter to expectations that it would help enable customers to more easily adapt to and hence be more successful on these rates, making them more inclined to remain enrolled. The Figure 20a shows retention rates after the first year for 10 treatment groups with PCTs, compared with 33 treatment groups without PCTs. These data reflect results for 9 CBS utilities. While the overall results vary somewhat, the average retention rates with and without PCTs are about the same: approximately 90% for those with PCTs, and about 89% for those without. Likewise, Figure 20b shows retention rates after the second year for 6 treatment groups with PCTs, compared with 28 treatment groups without PCTs. These data reflect results for 5 CBS utilities and exhibit a similar pattern of retention as in year 1: 91% with PCTs and 91% without PCTs.

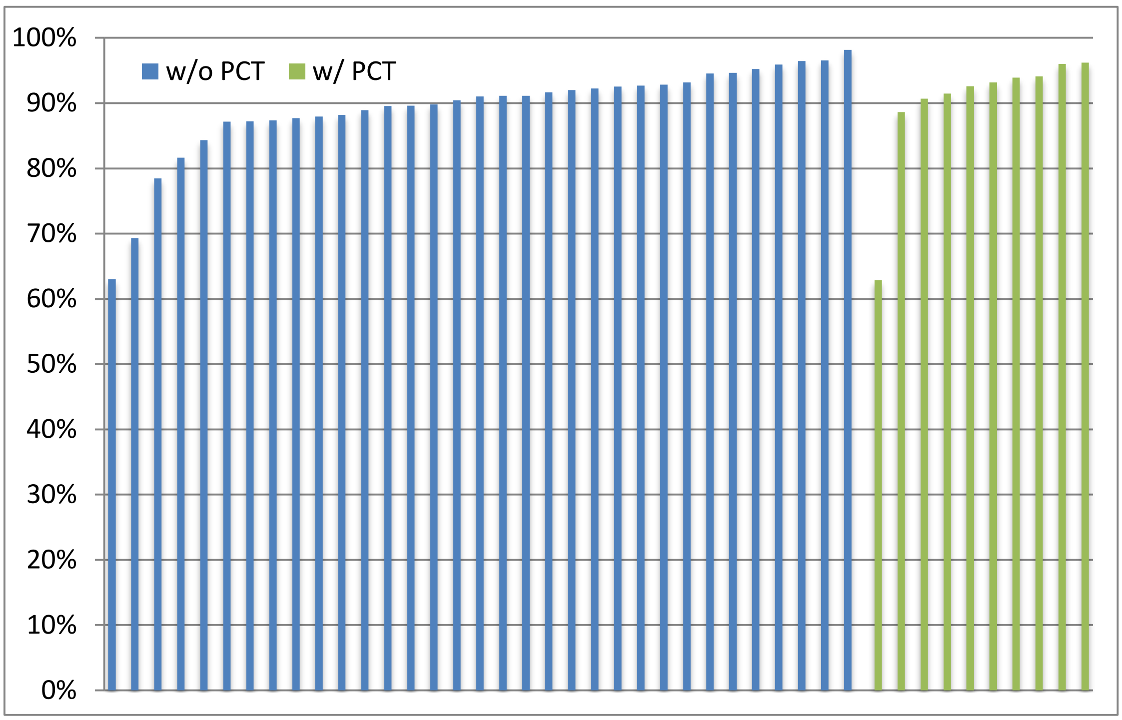


Figure 20a. Effects of PCTs on Retention Rates after the First Year of the Study by Treatment Group.

determine eligibility to participate in a PCT treatment. Any enrollment rate concerning PCTs resulting from such a recruitment process would be adversely affected by this lack of information as ineligible customers would be included in the population of customers recruited to participate in the study.

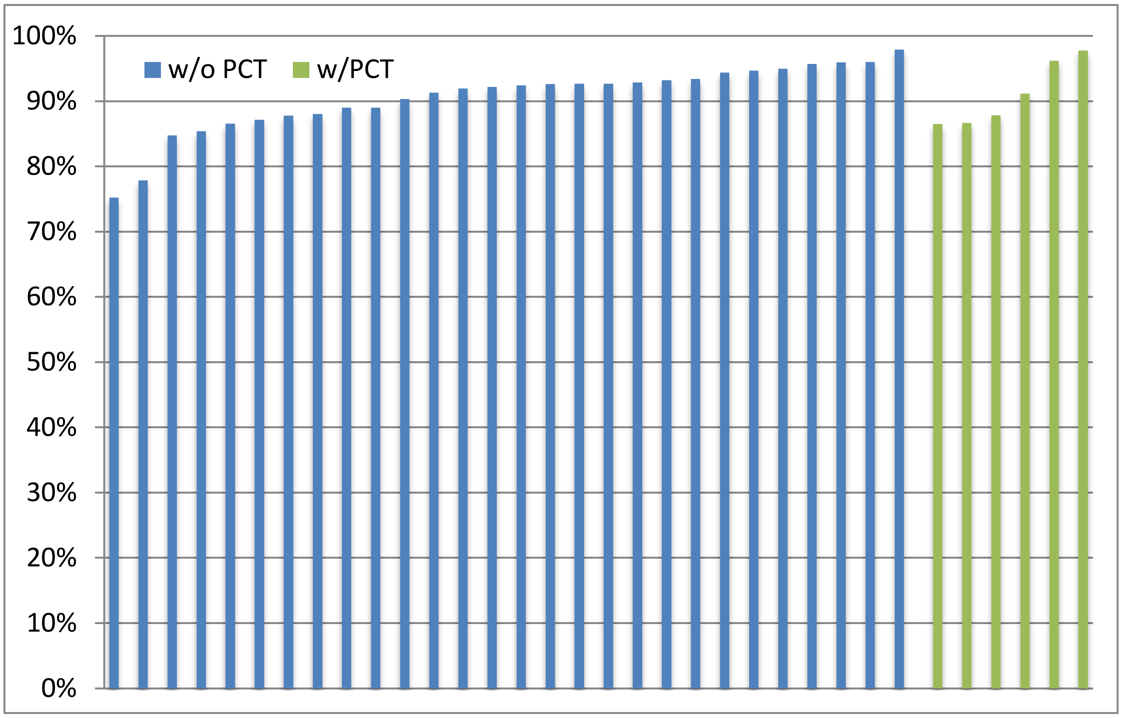


Figure 20b. Effects of PCTs on Retention Rates after the Second Year of the Study by Treatment Group.

6.2 Lessons Learned

PCTs are typically provided to customers with the understanding that utilities, not customers, will be the ones initially controlling thermostat set points during critical events. However, to promote acceptance, customers are typically given the ability to override utility controls if they are unhappy with the indoor comfort levels that result during critical peak events.

This approach relies on the theory of the default effect and is similar in concept to the application of that theory discussed in Chapter 3. In the case of PCTs, it is expected that customers, if left on their own, would be less likely to set the thermostat as high during critical events as the utility's control strategy. If the utility is able to pre-program the thermostat instead of the customer, the default bias suggests customers will be less likely to override the utility's higher thermostat control settings during events thereby maximizing the level of response.

The CBS utilities found that during the planning phases of the studies, market surveys and focus groups showed customers reluctant to have utilities in control of the PCTs during events and strongly preferred opting-in and retaining PCT control for themselves. However, once the devices were installed, and customers gained familiarity, most relaxed their concerns and allowed the utilities to control the PCTs during events after all. This lesson-learned suggests that utilities need to better address customers' initial concerns about control as these concerns are alleviated once experience is gained with the utility's control strategy for the PCTs. By doing so, it is likely more customers will be accepting of a utility-controlled PCT and thus the utility may be able to achieve higher aggregate demand reductions during all critical events.

6.3 Demand Reductions

While PCT offers did not appear to affect retention rates much, several of the CBS utilities found that demand reductions were higher for customers with PCTs than for those without. Figure 21 shows results for 8 CBS utilities encompassing 70 treatment groups and covers demand reductions for critical peak events involving CPP and CPR. The estimated demand reductions for customers with PCTs ranged from about 22% to 45%; while the estimated demand reductions for customers without PCTs ranged from about -1% to 40%.

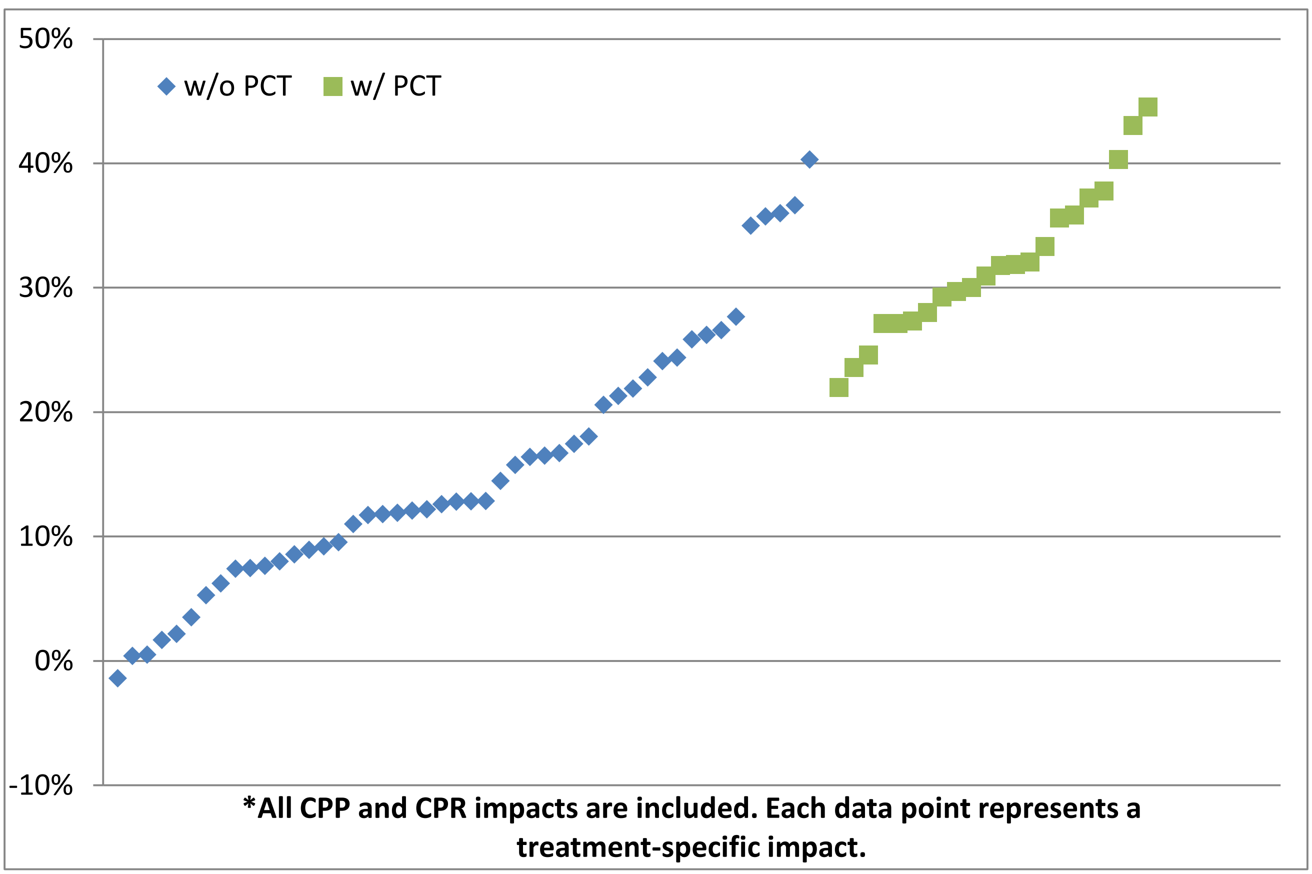


Figure 21. Average Percent Demand Reductions for Critical Event Days with and without PCTs by Treatment Group.

While PCTs generally increased the average level of demand reductions, if the devices also led to less variability in demand reductions, then the value would be increased further because of greater confidence by grid operators in the certainty of the resource. Figure 22 shows results from 3 CBS utilities and 19 CPP treatment groups. The results are generally inconclusive as certain PCT treatment groups showed less variability, while others showed greater variability. However, a separate analysis of average demand reductions for the critical peak events, and using NYISO's performance factor methodology described in Chapter 4, shows that grid operators would derate the average demand reduction 7% for CPP customers with PCTs, and 10% for CPP customers without PCTs. These results suggest that PCTs do reduce the level of variability of demand reductions associated with rates and programs, but only modestly so.

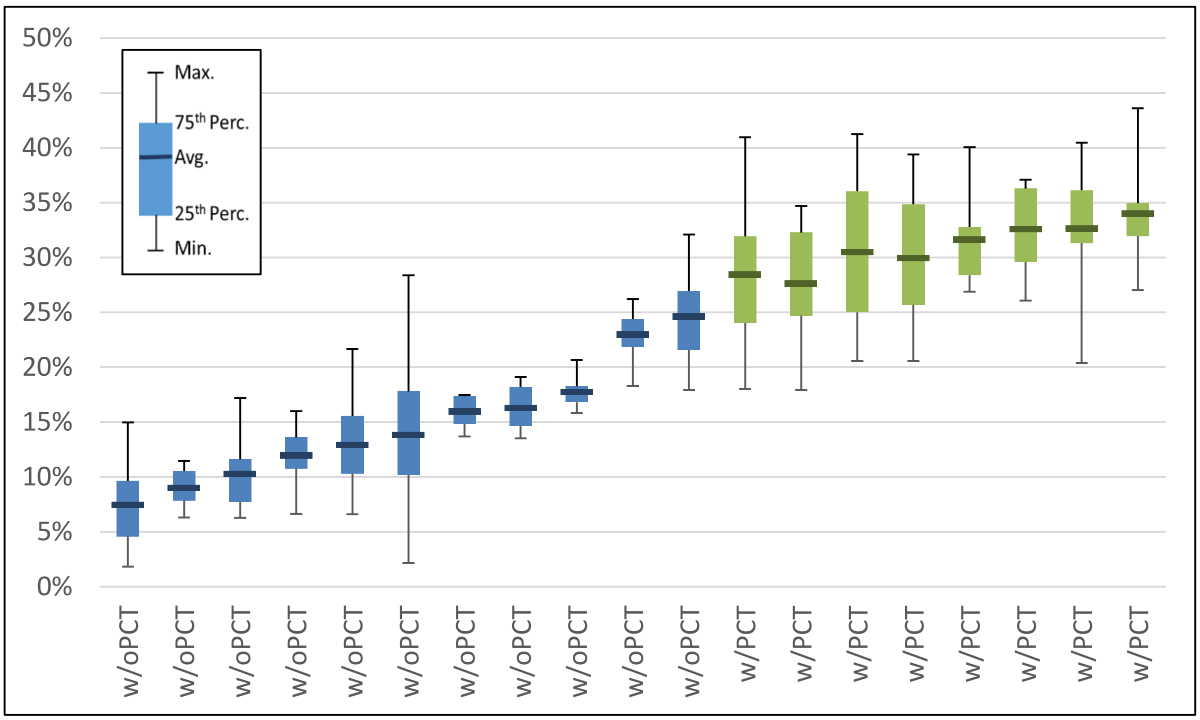


Figure 22. Variability of Per Customer Percent Demand Reductions for CPP Treatment Groups with and without PCTs by Treatment Group.

Utilities and other stakeholders are also interested in assessing the extent of anticipatory or remediation behaviors with respect to critical peak events (e.g., "pre-cooling" and "snap-back", respectively). The CBS evaluation results so far suggest there is not a clear pattern of pre-event behavioral changes on average; although these effects were observed in at least one of the individual studies. In contrast, after events, it does appear that customers with PCTs increased their electricity demand on average. This is consistent with prior studies, and is likely the result of strategies customers employ to raise thermostat set points during critical peak events and then lower the set points when the events are over.

Measuring the magnitude of this remediation (e.g., “snap-back”) effect, and the conditions under which it occurs, become increasingly important as participation in these types of demand response opportunities grows. At scale, these shifts in the timing of the maximum demand (later in the afternoon and early evening), and the need to bring on new power supplies to meet the increase in demand, will need to be forecasted accurately and subsequently managed by system operators.

6.4 Cost Effectiveness

OG&E conducted cost-effectiveness analysis of a broad roll out of its VPP rate offering which included offers of PCTs at no cost to participating customers. Shown in Table 9, the results use the standard cost effectiveness tests originally established by the California Public Utilities Commission in its Standard Practice Manual.[44] The table shows positive benefit-cost ratios in all of the standard tests. OG&E did not estimate benefit-cost ratios for simulated cases of the program without PCTs. The Total Resource Cost test results are comparable to the SMUD benefit-cost ratios for IHDs presented in Table 9. Based on these findings, OG&E filed a request, which was approved by the Oklahoma Corporation Commission, to roll-out the VPP rate offering with free PCTs under an opt-in recruitment approach with the goal of enrolling 120,000 (~20%) of its residential and small commercial customers across its service territory within 3 years.

[44] CPUC, “California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects” October, 2001.

Table 9. OG&E Cost Effectiveness Analysis Results for PCTs[45]	
Benefit-Cost Ratios	
Participant Test	1.50
Rate Impact Measure Test	1.01
Total Resource Cost Test	1.18
Societal Test	1.18
Program Administrator Cost Test	1.11

[45] OCC (2012). In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Approving its 2013 Demand Portfolio and Authorizing Recovery of the Costs of the Demand Programs through the Demand Program Rider. Oklahoma Corporation Commission. Cause No. PUD 201200134. Order No. 605737. Attachment B, Page 5 of 18, Table 1, Row "Smart Hours Program".

7. Customer Response to Price

Economic theory suggests that people are generally willing to buy larger quantities of a good as its price goes down. Conversely, as the price increases, people are expected to buy less of that same good. This basic relationship can be used to explain what is expected to happen when a TOU rate is introduced: electricity consumption should be reduced in the peak period when the price of electricity is raised while electricity consumption should be increased in the off-peak period(s) when the price is dropped.

A number of CBS utilities were interested in better understanding how such TOU rates could more broadly affect electricity usage during the highest priced hours of each day (i.e., peak period). To this end, these CBS utilities implemented TOU rates as part of their studies.[46] A subset of them also overlaid either a CPP or CPR rate onto the TOU rate in order to assess how customers would alter their peak period demand reduction in response to the higher event price. In general, the CBS utilities were interested in answering several key questions about their efficacy, including:

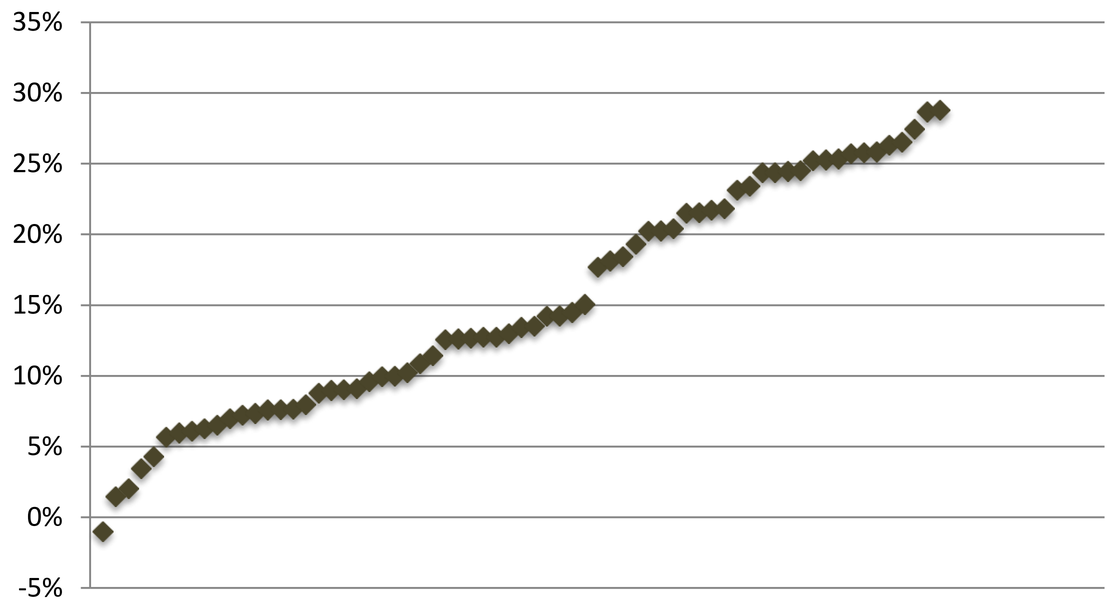
- What are the magnitude of peak period demand reductions?
- What are the effects on the magnitude of peak period demand reductions from the peak to off-peak price ratio?[47]
- What are the effects on the magnitude of peak period demand reductions from the existence of a PCT?
- What are the magnitude of event demand reductions?
- What are the effects on the magnitude of event demand reductions from the existence of a PCT?

[46] Because of the overlay nature of CPP and VPP, we focused on customer response estimates on non-event days. For OG&E's Variable Peak Pricing treatments, this meant we report customer response estimates on days when the rate was set at any level except Critical. Since VEC did not separately estimate customer response on days when the price threshold was not exceeded (i.e., standard TOU peak price was in effect) vs. when it was exceeded (i.e., variable peak price was in effect), we report the customer response estimate for all days.

[47] Since so few of the CBS utilities' reported elasticity estimates from their studies, which would be a more rigorous and direct way of assessing how changes in the price of electricity affects electricity consumption, the most comprehensive way of reporting peak period demand reductions available was to segment them by the peak to off-peak price ratio.

7.1 Peak Period Demand Reductions

The CBS utilities had a varied experience with customer response during the TOU rate's peak period. Figure 23 shows results for 5 CBS utilities encompassing 67 treatment groups and covers peak period demand reductions. The estimated demand reductions ranged from a low of -1% (i.e., load increased for the average customer in this TOU treatment by 1%) to a high of 29%, with an average of 15%.



***All TOU impacts are included. Each data point represents a treatment-specific impact.**

Figure 23. Average Percent Peak Period Demand Reductions by Treatment Group.

To better understand if differences in the TOU rate affected the level of peak period demand reduction, the estimated peak period demand reductions were grouped by their peak to off-peak price ratio:[48]

- Less than 2:1 price ratio;

[48] In order to compare across the different treatments, it is common to normalize the peak period price by the off-peak period price. The economic theory should still hold even if what is now being compared are price ratios and not just the price levels.

- 2:1-3:1 price ratio; and
- Greater than 4:1 price ratio.

Figure 24 shows the same average peak period demand reductions for the 67 separate TOU treatments organized by these three price ratio groupings. At the mean of each grouping, customers responded on average the least to the lowest price ratio (6% for a price ratio less than 2:1) and on average the most to the highest price ratio (18% for a price ratio greater than 4:1). However, the range of peak period demand reductions varied substantially within each price ratio grouping, at some points overlapping those from other price ratio groupings. This suggests something in addition to price may be driving differences in the observed response level.

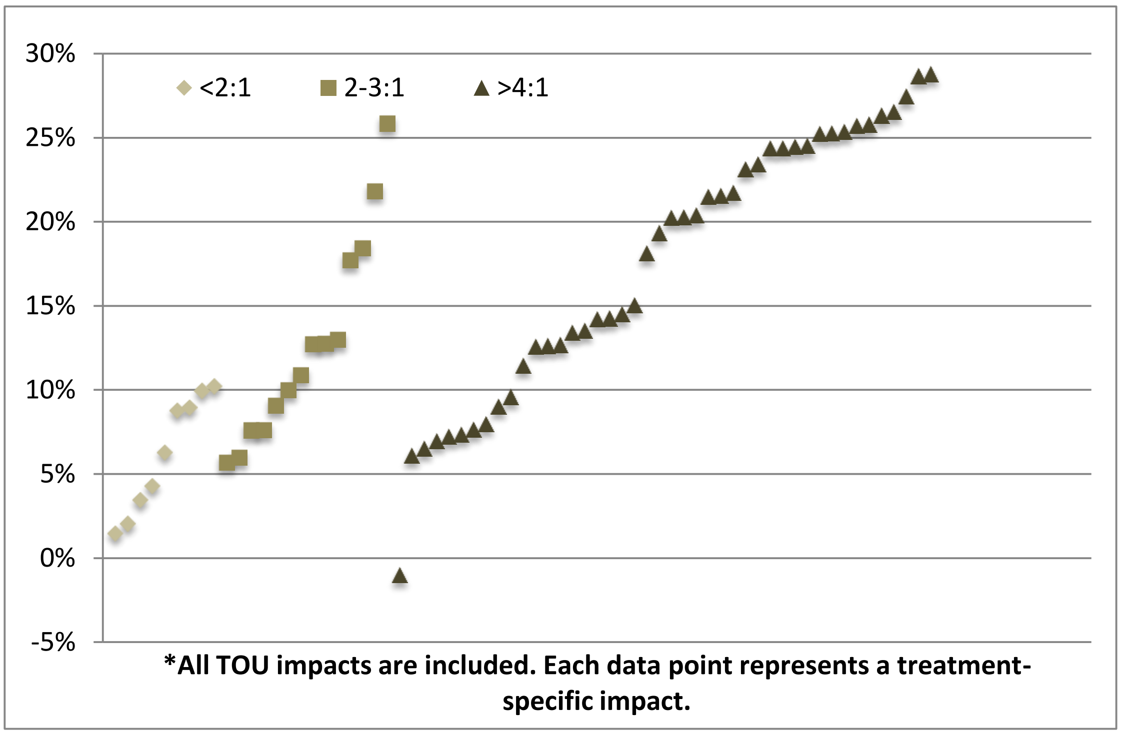


Figure 24. Average Percent Peak Period Demand Reductions by Treatment Group and Price Ratio Grouping.

Several CBS utilities included the offer of a PCT with their TOU rates. The peak period demand reductions can be further segmented by the existence or absence of a PCT. Figure 25 shows the peak period demand reductions for all 67 TOU treatments organized by price ratio grouping and existence of a PCT. At the lowest price ratios (i.e., those less than 2:1), a PCT seems to make little difference in the level of peak period demand reductions. However, as the price ratio increases to more moderate levels (i.e., between 2:1 and 3:1), we see the existence of a PCT makes a considerable difference as customers exhibit dramatically larger peak period load reductions when the control technology is available (average of 21% across all treatments) relative to when it is absent (average of 10% across all treatments). When the price ratio is at its highest (i.e., greater than 4:1), the role of a PCT in driving higher peak period demand reductions is not quite as clear. Although the average peak period demand reduction for treatments with PCTs is considerably higher than the average for treatments without PCTs (23% vs. 15%), there is considerable variability across treatments both with and without PCTs.

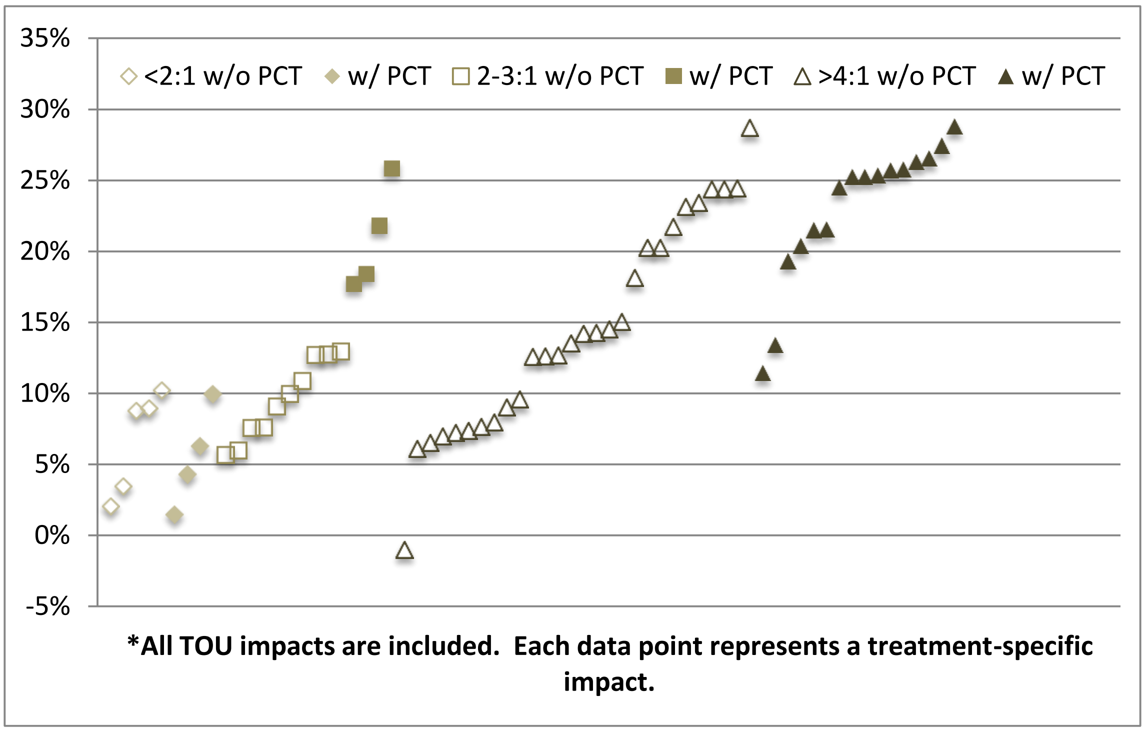


Figure 25. Average Percent Peak Period Demand Reductions by Treatment Group, Price Ratio Grouping and PCT.

7.3 Event Demand Reductions due to CPP/CPR

Four of the CBS utilities chose to overlay a CPP/CPR rate on the TOU rate to gauge the level of additional peak period demand reduction they could achieve during events relative to non-event days. Figure 26 shows results for 4 CBS utilities encompassing 23 treatment groups and covers event-only peak demand reductions. The average event peak demand reduction was 27% over all of the treatments, but ranged from 9% to 40%. This stands in contrast to non-event day peak period demand reductions, as described in Figure 23, where the average demand reduction over all treatments was 15%, with a range of -1% to 29%.

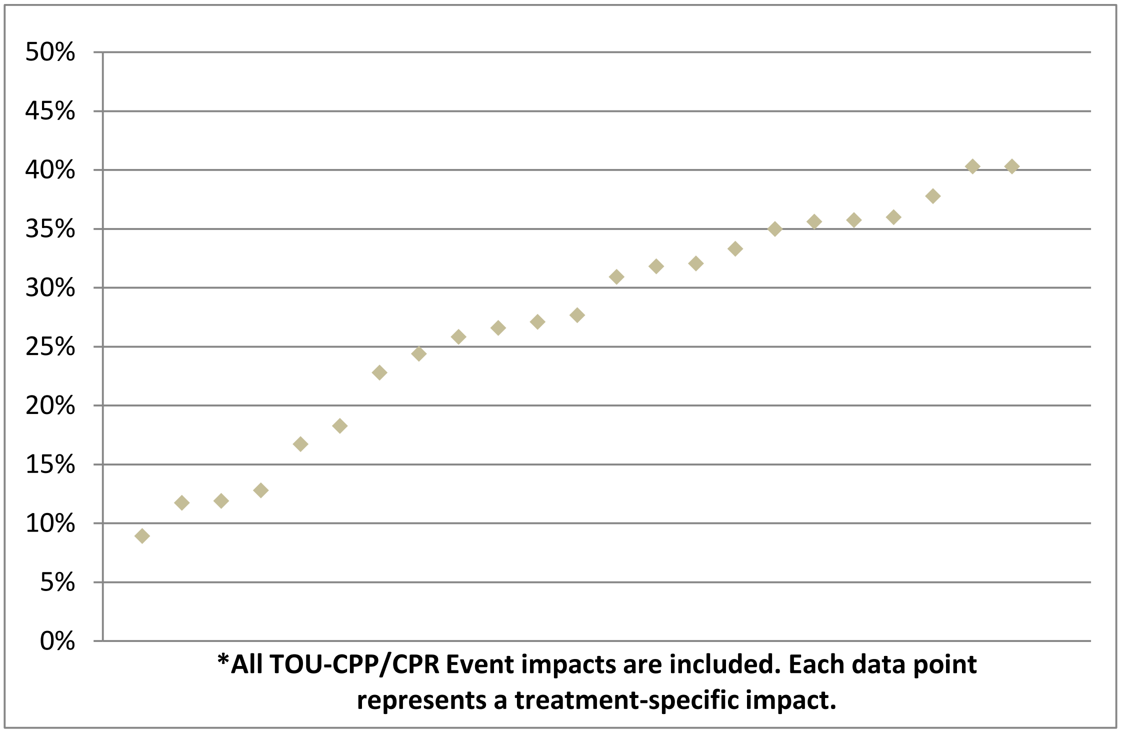


Figure 26. Average Percent Event Demand Reductions by Treatment Group.

Several of the CBS utilities also paired a PCT with their TOU CPP/CPR rate treatment. Figure 27 shows the same set of event demand reductions as portrayed in Figure 26, but this time organized by whether or not the treatment included a PCT. Consistent with the results presented in other chapters of this report, the existence of a PCT makes a difference to the response during events: 34% average demand reduction over all treatments when a PCT was present vs. 24% in the absence of a PCT.

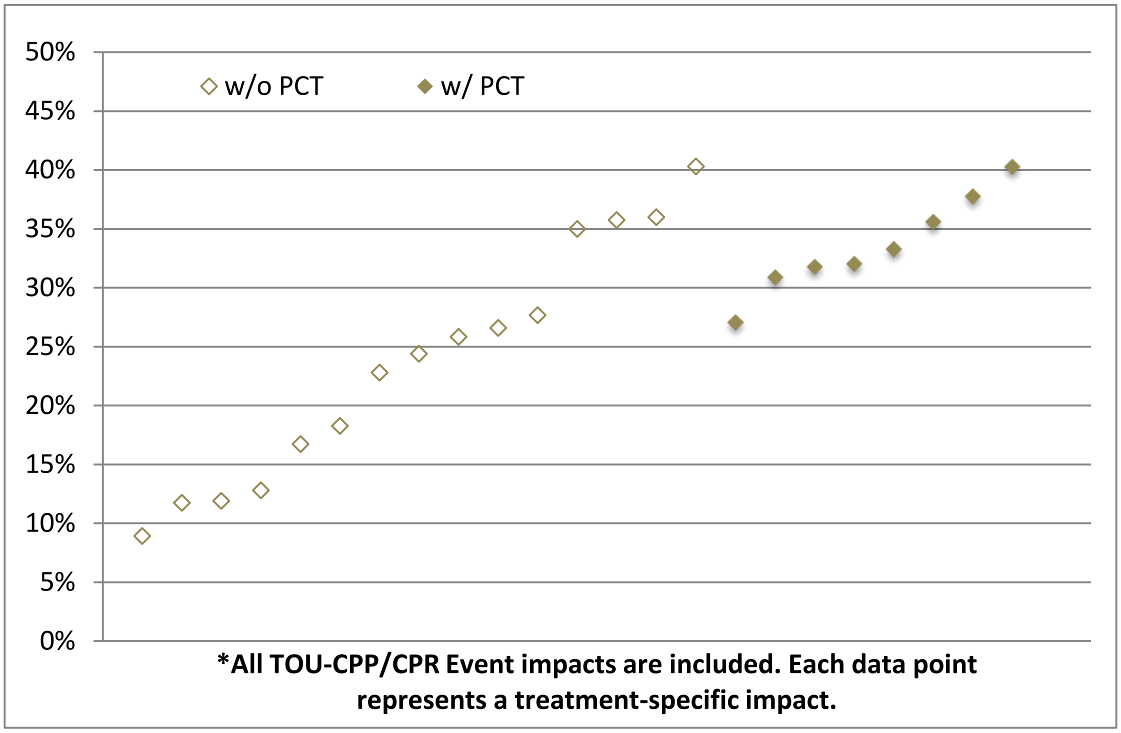


Figure 27. Average Percent Event Demand Reductions by Treatment Group with and without PCTs.

8. Conclusions

The CBS program effort produced a tremendous amount of novel insights about customer preferences for and responses to other time-based rate designs as well as information and control technology that are, at present, supportable by many regulators, policymakers and utilities.

8.1 Major Findings

Results from the CBS utilities can be grouped into five general areas:

(1) Recruitment approaches – effects of opt-in and opt-out;
(2) Pricing versus rebates – effects of CPP and CPR;
(3) Customer information technologies – effects of IHDs;
(4) Customer control technologies – effects of PCTs; and
(5) Customer response to prices – effects of TOU.

Table 10 summarizes major findings in these five areas and are each discussed in greater detail below.

Table 10. Summary of Major Findings	
Area	**Major Findings – Demand Reductions & Enrollment/Retention Rates**
Recruitment Approaches – Opt-in & Opt-out	• Opt-out enrollment rates were about 3.5 times higher than they were for opt-in (93% vs. 15%). • Retention rates for opt-out recruitment approaches (85.5% in year 1 and 88.5% in year 2) were about the same as they were for opt-in (89.7% in year 1 and 91.0% in year 2). • Peak period demand reductions for SMUD's opt-in TOU customers were about twice (13% in year 1 and 11% in year 2) as large as they were for opt-out customers (6% in year 1 and year 2). • Peak period demand reductions for SMUD's opt-in CPP customers were about 50% higher (24% in year 1 and 22% in year 2) than they were for opt-out customers (12% in year 1 and 14% in year 2). • SMUD's opt-out offers were more cost-effective for the utility than their opt-in offers in all cases. • Roughly two-thirds of those who were defaulted onto SMUD's TOU rates were expected to see bill impacts of +/- $20 for the entire 4 summer months the rates were in effect. • Based on survey responses, a majority of those defaulted onto SMUD's TOU rate were satisfied with the rate, regardless of the level of bill savings achieved, but those who saw the largest bill increases were generally less interested in continuing with the rate after the study ended.

Pricing Versus Rebates – CPP & CPR	• While opt-in enrollment rates for GMP were about the same for CPP (34%) and CPR (35%), retention rates were somewhat lower for CPP (80%) than they were for CPR (89%). • Average peak demand reductions for CPP (20%) were about 3.5 higher than they were for CPR (6%), but when automated controls (PCTs) were provided, they were about 30% larger (35% for CPP and 26% for CPR).
Customer Information Technologies - IHDs	• Enrollment and retention rates were generally unaffected by offers of IHDs. • SMUD's opt-in CPP customers with IHDs (26% in year 1 and 24% in year 2) had somewhat higher peak demand reductions than those without IHDs (22% in year 1 and 21% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's opt-in TOU customers with IHDs (13% in year 1 and 11% in year 2) had somewhat higher peak demand reductions than those without IHDs (10% in year 1 and 9% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's offerings without IHDs were more cost-effective for the utility in all cases than those with IHDs.
Customer Control Technologies - PCTs	• Enrollment and retention rates were generally unaffected by offers of PCTs. • Peak demand reductions are generally higher for CPP and CPR customer with PCTs (22% to 45%) than they were for customers without PCTs (-1% to 40%). • OG&E rate offers with PCTs were more cost-effective for the utility than those without PCTs.
Customer Response to Price - TOU	• Peak period demand reductions were far less, on average, for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak price ratio greater than 4:1). • When a CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction rose to 27% when averaged over all of the treatments • When PCTs were available, the differences in average peak period demand reductions were only affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1).

Recruitment Approaches – Effects of Opt-in and Opt-out

Results from the CBS utilities show that enrollment rates were much higher and peak demand reductions were lower under opt-out recruitment approaches, but that retention rates were about the same for both. Because of these results, there were overall benefit-cost advantages to using opt-out approaches over opt-in. When broken down further into customer sub-populations, based on those who were assumed to have actively made a choice to accept SMUD's default offer of a TOU rate (Always Takers) and those who simply didn't eschew it (Complacents), a subset of the Complacents seemed much less engaged, attentive and informed than the other study participants.

However, extending the results to apply to SMUD's entire residential population, this suggests that it is not the entirety of the residential class or even the full share of Complacents who are at-risk of being made worse off from a transition to default TOU, but rather a subset of the latter. Most importantly, these results suggest that there is a sizable share of the residential customer class at SMUD that was seemingly better off on a default TOU rate relative to the voluntary recruitment approach.

Prices versus Rebates – Effects of CPP and CPR

Results from the CBS utilities show that retention rates were higher for CPR than for CPP and demand reductions achieved without enabling control technology were generally higher for CPP than for CPR. However, when PCTs were available as an automated control strategy, the differences in peak demand reductions between CPP and CPR were largely eliminated.

Customer Information Technologies – Effects of IHDs

Results from the CBS utilities show that free IHD offers did not make a substantial difference for enrollment and retention rates. Although SMUD's peak demand reduction estimates were larger with IHDs, this result can be attributed to pre-treatment differences between the two groups so there was not a measured IHD effect on reductions of peak demand. As a result, cost-benefit ratios of rate offerings were lower when they included offers of free IHDs. In addition, many of the CBS utilities reported significant challenges with this relatively new technology. Problems included getting the IHDs to function properly and in one case the manufacturer decided to halt production and stop support.

Customer Control Technologies – Effects of PCTs

Results from the CBS utilities show that free PCT offers did not make a major difference for enrollment and retention, but that peak demand reductions were substantially higher. Unlike with IHDs, cost-benefit ratios for PCT offers were favorable. In response, one utility (OG&E) decided to roll-out a time-based rate with an offer of a free PCT to its entire residential customer class with a recruitment goal of 120,000 customers within three years.

Customer Response to Price – Effects of TOU

Results from the CBS utilities show that customers exhibited far less peak period demand reductions, on average, to the lowest TOU price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than to the highest TOU price ratio (18% for treatments with a peak to off-peak price ratio greater than 4:1). However, when PCTs were available as an automated control strategy, the differences in average peak period demand reductions were substantively affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1). When CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction was 27% when averaged over all of the treatments. However, when PCTs were available, the average event peak demand reduction was 34% vs. 24% when such automated control technology was not available.

8.2 Concluding Remarks

Rigorous experimental methods were applied in these consumer behavior studies with the hopes that more credible and precise load impact estimates would help resolve some of the outstanding issues hindering broader industry adoption of time-based rates for residential customers. Since none of the CBS utilities had any experience with such experimental methods, each CBS utility was provided with a small team of industry experts who provided technical assistance in the design, implementation and evaluation of each study. Besides direct engagement with each CBS utility, these Technical Advisory Groups (TAGs) also produced a library of guidance documents for the CBS utilities (which are publicly available on smartgrid.gov) on such diverse topics as study plan documentation, experimental design, rate and non-rate treatments, and evaluation techniques. With the help of these TAGs and the reference material they produced, many of the concerns initially raised about the application of experimental methods (e.g., withholding or deferring exposure to the rate after a customer had agreed to participate in the study would create customer relations problems) did not materialize. In addition, TAGs helped the utilities more narrowly focus their studies on a core set of objectives that would more readily and directly contribute to deliberations by each of the CBS utilities after the study about what to move forward with. As such, this consumer behavior study effort produced a wealth of contributory results on a number of critical issues the electric power industry was seeking information on, as described above.

Both utilities and participating customers learned a tremendous amount about themselves and their capabilities through these studies. Although not an explicit objective of the consumer behavior studies, their success hinged on the ability of the CBS utilities to effectively engage customers – many of whom had very limited experience in this arena. As such, several CBS utilities recognized the importance of performing market research during the study design phase to ensure marketing material was as effective as possible to engage customers as participants in the studies. The most successful CBS utilities continued that engagement not just during recruitment but throughout the study period itself, which included the creation of a plethora of different materials using a number of different mediums (e.g., monthly newsletters, social media campaigns of tips and tricks) that constantly sought to keep customers engaged in the study. Such efforts seemed to be quite successful, as the vast majority of customers who started the studies also completed them, expressed a high level of satisfaction in their experiences with these new rates and to a lesser extent with the new technologies, and continued taking service under the rate after the study ended, provided such opportunities were available.

It was hoped that this success would catalyze change in the electric industry both for those directly participating in these consumer behavior studies but also more broadly speaking for those totally unaffiliated with it. Three of the ten CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the ten CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. Specifically, OG&E has reached ~20% penetration of its residential class on the Variable Peak Pricing rate tested in its CBS after a little more than three years of marketing it. SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing heavily the very positive results SMUD achieved as grounds for this decision. DOE hopes the experiences and results from the CBS effort which have been published to date, as well as those yet to come, can help other utilities and regulators more aggressively pursue the application of time-based rates for residential customers.

Appendix – Summary of CBS Time-Based Rate Offerings[49]

KEY

CPP = Critical Peak Pricing
CPR = Critical Peak Rebate
TOU = Time of Use
IBR = Increasing Block Rate
Flat = Constant Price

All prices have been rounded to 3 decimal places.

GMP

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
Green Mountain Power	Treatment	CPP	0.144	0.60
	Treatment	CPR	0.148	-0.60
	Control	Flat	0.148	0.148

DTE

Utility	Customer	Rate Type	Off Peak ($/kWh)	Mid Peak ($/kWh)	Peak ($/kWh)	Critical Peak ($/kWh)
Detroit Edison	Treatment	TOU+CPP	0.04	0.07	0.12	1.00
	Control	IBR	0.069/kWh for the first 17 kWh per day; 0.083/kWh for excess consumption over 17 kWh per day.			

FirstEnergy-CEIC

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
FirstEnergy	Treatment	CPR	0.03	-0.40
	Control	Flat	0.03	0.30

[49] This summary of rate offerings are for the six CBS utilities that had produced initial or final evaluation reports at the time this report was written.

MMLD

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
Marblehead Municipal Light District	Treatment	CPP	0.09	1.05
	Control	Flat	0.143	0.143

OG&E

Utility	Customer	Rate Type	Off Peak ($/kWh)	Variable Peak 1 ($/kWh)	Variable Peak 2 ($/kWh)	Variable Peak 3 ($/kWh)	Variable Peak 4 ($/kWh)	Critical Peak ($/kWh)
Oklahoma Gas & Electric	Treatment	TOU+CPP	0.042	0.23	0.23	0.23	0.23	0.46
	Treatment	VPP+CPP	0.045	0.045	0.113	0.23	0.46	0.46
	Control	IBR	0.084/kWh for consumption up to 1,400 kWh; 0.097/kWh for consumption beyond 1,400kWh					

SMUD

Utility	Customer	Rate Type	Peak ($/kWh)	Critical Peak ($/kWh)	Tier 1 ($/kWh) 0-700kWh	Tier 2 ($/kWh) 701-1425kWh	Tier 3 ($/kWh) 1426+kWh
Sacramento Municipal Utility District	Treatment	CPP	n/a	0.75	0.085	0.167	0.167
		TOU	0.27	n/a	0.085	0.166	0.166
		TOU+CPP	0.27	0.75	0.072	0.141	0.141
	Control	IBR	n/a	n/a	0.102	0.183	0.183
	Treatment EAPR	CPP	n/a	0.50	0.055	0.117	0.167
		TOU	0.20	n/a	0.055	0.116	0.166
		TOU+CPP	0.20	0.50	0.049	0.099	0.141
	Control EAPR	IBR	n/a	n/a	0.066	0.128	0.183

*EAPR stands for “Energy Assistance Program Rate”, which is a program that provides discounted electricity rates to low-income residents.

Demand Response Market Research:

Portland General Electric, 2016 to 2035

PREPARED FOR

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I. Introduction

Interest in demand response (DR) in the Pacific Northwest has grown considerably since Portland General Electric's (PGE's) first DR potential study was conducted in 2009 and subsequently updated in 2012.[1] A need to integrate growing amounts of intermittent resources (e.g., wind and solar) into the grid, increasingly stringent constraints on the operation of regional hydro generation, growth in summer peak demand, and an expectation of a capacity shortfall in the next five years have all driven interest in DR.

As a result of this growing interest from stakeholders, several new studies have explored the potential for DR to address these issues. For instance, in 2014 the Northwest Power and Conservation Council (NPCC) completed a study to assess the market for various flexible load resources.[2] In that same year, PacifiCorp completed a detailed DSM potential study spanning all of its jurisdictions, with considerable attention being paid to DR programs.[3] That study was noted for the considerable role that demand-side resources will play in future resource planning efforts. Several demonstration projects and pilot studies are now also underway in the region, including the involvement of the Bonneville Power Administration (BPA), Pacific Northwest National Laboratory (PNNL), and many regional utilities including PGE.

To better inform its own DR initiatives and to establish inputs to its integrated resource planning (IRP) process, PGE contracted with The Brattle Group to develop an updated DR potential study ("the 2015 study"). The purpose of this study is to estimate the maximum system peak demand reduction capability that could be realistically achieved through the deployment of specific DR programs in PGE's service territory under reasonable expectations about future market conditions. The study also assesses the likely cost-effectiveness of these programs.

The 2015 study includes several improvements over the prior studies commissioned by PGE, both in terms of the quality of the data being relied upon and the breadth of issues which it addresses. Specific improvements in the 2015 study include the following:

1 The Brattle Group and Global Energy Partners, "Assessment of Demand Response Potential for PGE," prepared for PGE, March 16, 2009. Also, Ahmad Faruqui and Ryan Hledik, "An Assessment of Portland General Electric's Demand Response Potential," prepared by The Brattle Group for Portland General Electric, November 28, 2012.

2 Navigant, "Assessing Demand Response Program Potential for the Seventh Power Plan: Updated Final Report," prepared for the Northwest Power and Conservation Council, January 19, 2015.

3 Applied Energy Group and The Brattle Group, "PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034," prepared for PacifiCorp, January 30, 2015.

- Market data was updated to account for changes in forecasts of the number of customers by segment, seasonal peak demand, the expected timing and cost of new capacity additions, and other key assumptions that drive estimates of DR potential and its cost-effectiveness.

- Assumptions about DR participation and impacts were updated to reflect emerging DR program experience in the Pacific Northwest. Ten regional studies conducted in the past five years in the region informed these updates.

- The findings of 24 new dynamic pricing pilots, conducted both in the U.S. and internationally, were incorporated to refine potential estimates for pricing programs. This allowed several important aspects of pricing potential to be accounted for, including seasonal impacts and differences in price response when programs are offered on an opt-in versus opt-out basis.

- A survey of market research studies and full-scale time-varying pricing deployments was utilized to improve assumptions around participation in dynamic pricing programs.

- The methodology for estimating the cost-effectiveness of the DR programs, while conceptually consistent with the prior PGE potential studies, was improved to address comments from the Oregon PUC regarding the derating of avoided costs to account for operational constraints of the DR programs. Accounting for incentive payments on the cost-side of the analysis was also refined.

- The menu of program options analyzed was significantly expanded to include several newly emerging options that have recently begun to generate interest among utilities around the country, such as smart water heating load control, behavioral DR, electric vehicle charging load control, and "bring-your-own-thermostat" programs.

A few key points should be kept in mind while reading this report:

1. The load reduction potential and cost-effectiveness of each DR option are evaluated in isolation from each of the other options; they do not account for potential overlap in participation that may occur if several DR options were simultaneously offered to a single customer segment. Therefore, the potential estimates of the individual DR options are not additive and the economics of the programs may change when the DR options are offered as part of a portfolio.

2. The analysis is based on typical program designs with illustrative yet realistic incentive payments. Rather than being the final word on the cost-effectiveness of these programs, findings should be used as a starting point for further exploring how different program designs would change the economics of the programs.

3. Unless otherwise noted, peak reduction potential estimates are reported for the year 2021. This was chosen as the reporting year of interest, because it is the first year in which PGE is projected to need new capacity.

4. Any options requiring a change to the rate structure could not be offered until 2018 or 2019 due to constraints with the current billing system.

5. In all cases, the cost of advanced metering infrastructure (AMI) is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

6. As is discussed in the Methodology section of this report, the estimates of potential are not projections of what is likely to occur. Rather, they represent an estimated upper-bound on what is achievable under current expectations of future system conditions and reflect utility experience with successful DR programs around the country. Achieving this potential will require a significant customer outreach and education effort and will likely take time, given the relative lack of experience with DR in the Pacific Northwest relative to other parts of the country. Like energy efficiency, successful DR programs require active customer participation. DR in the Pacific NW is in a similar place to where energy efficiency was in the region in the late 1970s or early 1980s. The region – and PGE – has the potential to achieve a significant amount of DR, but there is an upfront investment in awareness and program design that will be required to meet this potential. Ultimately, PGE's ability to achieve significant impacts through DR programs will depend on customer understanding and acceptance of the programs.

The remainder of this report is organized as follows. Section 2 describes the various DR options that were analyzed. Section 3 summarizes highlights of the methodology for estimating potential and evaluating cost-effectiveness. Section 4 presents the key findings of the study. Section 5 concludes with a discussion of considerations for PGE's ongoing and future DR initiatives. The report is intended to be a concise summary of the highlights of the study; the appendices contain significantly more detail on methodology and assumptions.

II. The DR Options

Thirteen different types of DR programs were analyzed in this study. Eligibility for the programs varies in part by customer segment. PGE's customer base was divided into five customer classes. Customer class definitions were determined based on both applicability of DR programs and data availability.

- Residential: All residential accounts
- Small Commercial & Industrial (C&I): Less than 30 kW of demand
- Medium C&I: 30 kW to 200 kW of demand
- Large C&I: More than 200 kW of demand
- Agricultural: All agriculture accounts

Non-metered customers, such as street lighting, were excluded from the analysis, as were customers who have chosen direct access.

Accounting for the number of DR programs offered to each customer segment, a total of 28 different options were analyzed. For organizational purposes, the DR programs can be assigned to three categories: (1) Pricing options, (2) conventional non-pricing options, and (3) newly emerging DR options.

PRICING OPTIONS

AMI-enabled rate options include prices that vary by time of day. The potential in each pricing option was modeled both with and without the adoption of enabling technology. For residential and small C&I customers, the enabling technology is assumed to be a programmable communicating thermostat (PCT), also known as a smart thermostat, which would allow the customer to automate reductions in heating or cooling load during times when the price in the retail rate is high. For medium and large C&I customers, the enabling technology is Auto-DR, which can be integrated with a building's energy management system to facilitate a range of automated load reduction strategies.

Time-of-use (TOU) rate: A TOU rate divides the day into time periods and provides a schedule of rates for each period. For example, a peak period might be defined as the period from 3 pm to 8 pm on weekdays and Saturdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the average variation in the cost of supply (including marginal capacity costs). In some cases, TOU rates may have a shoulder (or mid-peak) period, or particularly in the winter season, two peak periods (such as a morning peak from 6 am to 10 am, and an afternoon peak from 3 pm to 8 pm). Additionally, the prices and period definitions might vary by season. With a TOU rate, there is certainty as to what the prices will be and when they will occur.

Critical peak pricing (CPP): Under a CPP rate, participating customers pay higher prices during the few days when wholesale prices are the highest or when the power grid is severely stressed (i.e., typically up to 15 days per year during the season(s) of the system peak). This higher peak price reflects both energy and capacity costs. In return, the participants receive a discount on the standard tariff price during the other hours of the season or year to keep the utility's total annual revenue constant. Customers are typically notified of an upcoming "critical peak event" one day in advance.

Peak Time Rebate (PTR): Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours. Customers stay on the standard rate at all hours. The program is analogous to the pay-for-curtailment programs that have been offered to large commercial and industrial customers in restructured markets for many years. Opt-out deployments of PTR are being offered by BGE and Pepco to residential customers in Maryland. These relatively new programs will provide more information in the next few years as their impact evaluations become available.

Conventional Non-Pricing Programs

There is a long history of experience with conventional non-pricing programs in the U.S. These programs provide customers with incentive payments or bill credits in return for relatively dependable load reductions and do not require AMI.

Direct load control (DLC) for heating and cooling: With heating/cooling DLC the utility controls a customer's electric heating or central air-conditioning equipment on short notice. In exchange for participating, the customer receives an incentive payment or bill credit. Recent DLC programs have involved the installation of smart thermostats for customers, which allow remote adjustment of temperature settings, so the utility can remotely adjust the temperature to reduce demand from central air-conditioning (CAC) and central space heating units. After an event, load control is released, allowing the thermostat control to revert back to the customer's original settings.

Water heating DLC: Like DLC for heating and cooling, water heating DLC allows the utility to control the load of electric resistance water heaters. The water heating element is turned off during times when load reductions are needed, and turned back on before the average water temperature in the tank drops below a minimum threshold. In some applications, the water is superheated during nighttime hours to allow for longer periods of load curtailment during the day. One difference between water heating DLC and space heating/cooling DLC is that water heaters are used, on average, year-round and during all hours of the day, and can be interrupted without any detectable impact by the customer.

Curtailable tariff. This is similar to PGE's Firm Load Reduction program (Schedule 77).[4] Under a curtailable tariff, eligible customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year) and are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment varies with the load commitment level and the amount of notice required (e.g., number of hour or minutes). In addition to the fixed capacity payment, participants typically receive a payment for energy reduction. Since load reductions must be of firm resource quality, curtailment is often mandatory and penalties can be assessed for under-performance or non-performance.

Third-party C&I DLC: This is similar to PGE's Energy Partner program. With Third Party DLC, an "aggregator" (also known as a "curtailment services provider") works with customers to establish protocols to automate load reductions at times when they are needed from PGE. PGE purchases the aggregated load reduction from the aggregator, who shares the revenues with the customers who participate in the program. With the Third Party DLC program, customer recruitment and certain operational aspects of the program are handled by the aggregator rather than the utility.

EMERGING DR OPTIONS

Several new DR options were analyzed in this study. These are DR options with which there is relatively limited experience to-date. However, the programs have garnered significant interest from utilities around the U.S. recently and are beginning to be tested through pilot programs and some full-scale rollouts.

Bring-your-own-thermostat (BYOT): In a BYOT program, customers who already own a smart thermostat are paid to participate in a DLC program. An advantage of this program over a traditional heating/cooling DLC program are that the customer already has the necessary equipment, so there are no equipment or installation costs associated with the program. Additionally, given that the customer has made the decision to invest in a smart thermostat, it is likely that participants are already more engaged in their energy usage than the typical customer. In PGE's service territory, the market penetration of central A/C is growing rapidly and the Energy Trust of Oregon (ETO) is promoting the adoption of smart thermostats for energy efficiency benefits, suggesting that the eligible customer base for such a program will grow considerably in the coming years. Even the low-end of the range of national studies on likely smart thermostat adoption suggests that 25 percent of households will be equipped with a smart

[4] Whereas PGE's Schedule 77 program has a specific design and incentive structure developed by PGE, our assessment of the Curtailable Tariff program in this study is based on average participation across a range of curtailable tariff program designs in the U.S. In this sense, our analysis is for a more generic design that is a hybrid of these programs.

thermostat by 2020.[5] Several utilities, such as Austin Energy, Southern California Edison, ConEd, and Hydro One have recently introduced BYOT programs. PGE is currently exploring this program option through a pilot program with Nest Labs.

Behavioral DR (BDR): In a BDR program customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. BDR can be thought of as a PTR without the rebate payment. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Customer response is driven by new information that they didn't previously have. BDR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, BGE, and four Minnesota cooperatives.

Smart water heating DLC: In contrast to the conventional water heating DLC program described above, smart water heating DLC accounts for an emerging trend toward the availability and adoption of "DR-ready" water heaters. These water heaters come pre-equipped with the communications capability necessary to participate in a DR program and have the potential to offer improved flexibility and functionality in the control of the heating element in the water heater. Rather than simply turning the element on or off, the thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. This has the potential for facilitating the integration of intermittent sources of generation. Smart water heating DLC was modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters in the Pacific Northwest and are the most attractive candidates for a range of advanced load control strategies.[6]

EV charging load control: EVs represent a potentially flexible source of nighttime load, and adoption of EVs is projected to grow in the future. This study focuses only on the potential to control home charging of personal EVs. It does not include, for example, load control at public charging stations or for commercial fleets.

5 Berg Insight, "Smart Homes and Home Automation," January 2015.

6 It may also be possible to control the load of heat pump water heaters, though there is more uncertainty around the technical and economic effectiveness of this option.

III. Methodology

This study focuses on estimating "maximum achievable potential." This is founded in the assumption that enrollment rates in the DR programs reach the levels attained in successful DR programs being offered around the country. Therefore, while the assumed enrollment levels have been demonstrated to be achievable by other utilities, they represent an approximate upper-bound based on recent DR experience. In other words they represent some of the highest enrollment levels observed in DR programs to-date.

A few factors suggest that PGE may be able to attain levels of enrollment approaching what the very top programs have achieved nationally:

1. There has been a long history of success with energy efficiency programs in PGE's service territory, suggesting that customers are open to participating in energy management programs.
2. PGE has an environmentally conscious customer base.
3. There has been a trend toward the rising adoption of new energy management products, such as smart thermostats, in the region.
4. Growth in summer peak demand means that DR programs that were previously not applicable to PGE's service territory can now be productively offered to customers.

At the same time, it is important to note that it will likely take time for PGE to approach these levels of enrollment. PGE, like much of the rest of the Pacific Northwest, is starting from a point of limited experience with DR programs and low energy prices relative to utilities in other regions of the U.S., and customers will need to be educated about the benefits of the programs before having the confidence to enroll. To some extent, this appears to have been the experience thus far with the Energy Partner program. Nationally, the most successful DR programs often required years of promotion and experimentation by utilities and aggregators before achieving the high enrollment levels that are observed today.

DR potential is estimated using empirically-based assumptions about the eligible customer base, participation, and per-customer impacts. The fundamental equation for calculating the potential system impact of a given DR option is shown in Figure 1 below. Market characteristics (e.g. system peak demand forecast, customer load profiles, number of customers in each class, appliance saturations) were provided by PGE.

Figure 1: The DR Potential Estimation Framework

Potential DR Impact	**=**	**Total Demand of Customer Base**	**X**	**% of Base Eligible to Participate**	**X**	**% of Eligible Customers Participating**	**X**	**% Reduction in demand per participant**

PARTICIPATION

Two variations of maximum achievable potential were estimated for the pricing options (TOU, CPP, PTR), based on different assumptions about the manner in which these programs would be offered to customers. Opt-in deployment assumes that customers would remain on the currently existing rate and would need to proactively make an effort to enroll in the dynamic rate. Default deployment (also known as opt-out deployment) assumes that customers are automatically enrolled in a dynamic rate with the option to revert back to the otherwise applicable tariff if they choose. Default rate offerings are typically expected to result in significantly higher enrollment than when offered on an opt-in basis. Default deployment of dynamic pricing for residential customers is currently uncommon, although TOU rates have been rolled out on an opt-out basis across the province of Ontario, Canada and throughout Italy. PTR has been offered on an opt-out basis by Southern California Edison, Baltimore Gas & Electric (BGE), and Pepco Holdings in Maryland and Washington, D.C.

Participation in the pricing programs was based on a review of market research studies and full-scale deployments of time-varying rates. The market research studies used a survey-based approach to gauge customer interest in the various pricing options, while the full-scale deployments reflect actual experience in the field. Opt-in participation rates range from 13 to 28 percent, which varies by pricing option and customer segment. When offered on an opt-out basis, the participation assumptions range from 63 to 92 percent.

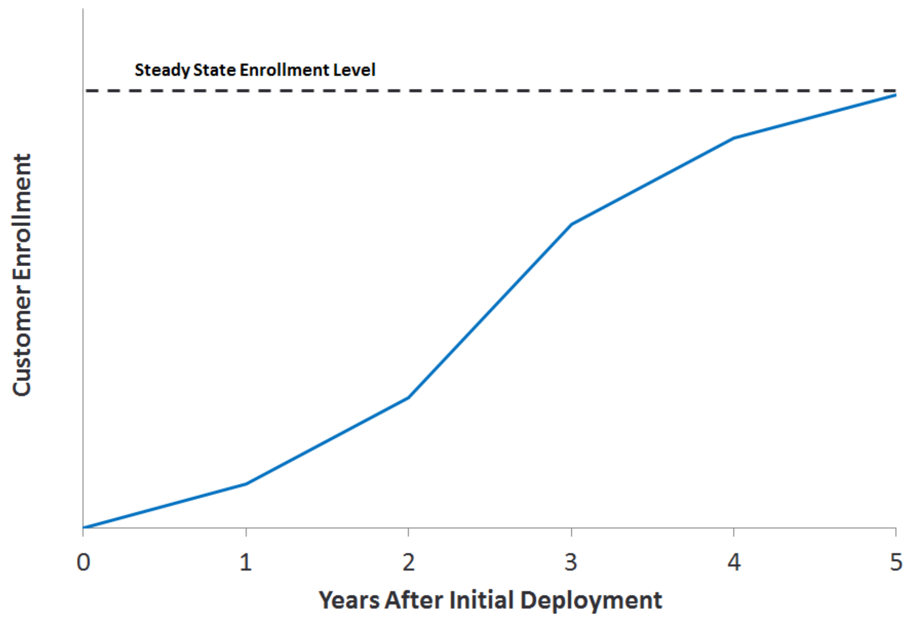
Participation in the conventional non-pricing programs is based on a review of DR program data collected by the Federal Energy Regulatory Commission (FERC).[7] FERC surveyed U.S. utilities to gather information on the types of DR programs they offer, the number of customers enrolled, the peak demand reduction capability of the programs, and several other variables. To establish a reasonable upper-bound on participation for this study, the 75th percentile of the distribution of participation rates in each program in the FERC database was used as the basis for enrollment. The resulting participation rates generally range from 15 percent to 25 percent, although they are higher in a few instances where significant enrollment has been observed (e.g., large C&I curtailable tariff enrollment of 40%).

Enrollment in emerging DR options (BYOT, behavioral DR, smart water heating DLC) was based largely on the experience of pilot programs, because by nature there is limited full-scale experience with the emerging options at this point. In instances where the programs have not been piloted, expert judgment was used to develop plausible enrollment estimates that were intuitively consistent with participation assumptions for other programs in the study.

7 FERC, "Assessment of Demand Response and Advanced Metering," December 2012. Supporting database: http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

Changes in participation are assumed to happen over a five-year timeframe once the new programs are offered. The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the five-year period, and then slows over the second half (see Figure 2). A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options. This reflects an aggressive ramp-up in participation for a utility with relatively limited DR experience like PGE. See Appendix A for more detail on the development of the participation assumptions.

Figure 2: Illustration of S-shaped diffusion curve



Per-participant Impacts

Per-participant impacts for the pricing options were based on the results of 225 different pricing tests that have been conducted across 42 residential pricing pilots over roughly the past 12 years.[8] These pilots have almost universally found that customers do respond to time-varying rates, and that the amount of price responsiveness increases as the peak-to-off-peak price ratio in the rate increases. The simulated impacts that were simulated for PGE in this study account for this non-linear relationship between a customer's price responsiveness and the peak-to-off-peak price ratio. The impacts also account for differences by season, across rate designs, and whether the rates are assumed to be offered on an opt-in or default basis. The study has assumed a price ratio of two-to-one in the TOU rate, four-to-one in the CPP rate, and eight-to-one in the PTR rate.

[8] Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

These price ratios were provided by PGE based on rate designs that they would consider offering in the future.

Impacts for conventional non-pricing programs remained relatively stable relative to PGE's 2012 DR potential study, given the long history of experience with these programs in the U.S. In this updated study for PGE, those impact assumptions were refreshed based on a review of ten DR pilot programs that have been conducted in the Pacific Northwest. For the emerging DR options, impacts were based on the findings of pilots where available and otherwise calibrated to the impacts of other DR programs in the study to ensure reasonable relative impacts across the programs. While estimates of impacts associated with all of the programs have some degree of uncertainty, there is less uncertainty in the impacts of the conventional and pricing programs due to significant experience with these programs through both a full-scale rollouts and scientifically rigorous pilots. There is a higher degree of uncertainty in the impacts of the emerging DR programs as, by nature, they are newer and less tested. See Appendix B for more detail on the development of the per-participant impact assumptions.

COST-EFFECTIVENESS

The cost-effectiveness of each DR option was assessed using the total resource cost (TRC) test. The TRC test measures the total benefits and costs of a program, including those of both the utility and the participant. The TRC test is the cost-effectiveness framework that is commonly used by the Oregon PUC to assess the economics of demand-side programs. The present value of the benefits is divided by the present value of the costs to arrive at a benefit-cost ratio. Programs with a benefit-cost ratio greater than 1.0 are considered to be cost-effective. [9]

Benefits in the cost-effectiveness analysis include:[10]

- Net avoided generation capacity cost ($145/kW-yr)[11]
- Avoided peak-driven T&D cost ($31/kW-yr)
- Avoided peak energy cost ($32/MWh, growing over time)

9 For further information on cost-effectiveness analysis of DR programs, see Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

10 Avoided cost estimates were provided by PGE and reviewed by The Brattle Group for reasonableness.

11 The total cost of a peaking unit is reduced by an estimate of the unit's expected energy margins to arrive at a net avoided cost that would be roughly equivalent to the net cost of new entry (CONE) in an organized capacity market.

Costs in the cost-effectiveness analysis vary by program type and include:[12]

- Program development
- Administrative
- Equipment and installation
- Operations and maintenance
- Marketing and recruitment
- Incentive payments to participants

Treatment of participant incentives as a cost was given close consideration in the study. There is not a standard approach for treating incentives when assessing the cost-effectiveness of DR programs. In some states, incentive payments are simply considered a transfer payment from utilities (or other program administrators) to participants, and therefore are not counted as a cost from a societal perspective. Others suggest the incentive payment is a rough approximation of the "hassle factor" experienced by participants in the program (e.g., reduced control over their thermostat during DR events), and should be included as a cost.

While there is some merit to the latter argument – that customers may experience a degree of inconvenience or other transaction costs when participating in DR programs – the cost of that inconvenience is overstated if it is assumed to equal the full value of the incentive payment. If that were the case, then no customer would be better off by participating in the DR program. For example, it would be unrealistic to assume that an industrial facility would participate in a curtailable tariff program if the cost of reducing operations during DR events (e.g., reduction in output) exactly equaled the incentive payment for participating. In reality, customers participate in DR programs because they derive some incremental value from that participation. Further, in some DR programs customers experience very little inconvenience. Some A/C DLC programs, for instance, can pre-cool the home and manage the thermostat in a way that few customers report even being aware that a DR event had occurred, let alone a loss of comfort.

Given the uncertainty around this assumption, this study counts half of the incentive payment as a cost in the cost-effectiveness analysis. Two sensitivity cases were also analyzed, exploring how the findings change when the full incentive is counted as a cost as well as when it is entirely excluded from the calculation.[13] This is similar to the approach adopted by the California Public

[12] Costs of the programs were typically annualized over a 15-year life in this study. Fifteen years is an illustrative but plausible assumption. While the life of individual appliances and technologies will vary around this number, the impact of that variance is well within the magnitude of other uncertainties in the analysis such as projections of marginal costs and load growth. In future research, sensitivity analysis could be conducted around uncertain variables such as these to develop a better understanding of the key drivers of the findings.

[13] See Appendix C for the results of the sensitivity cases. Relative to the case where half of the incentive is included as a cost, when none of the incentive is included as a cost, water heating load control for

Utilities Commission, which considers a range of treatments of the incentive payment when evaluating DR cost-effectiveness.

Another important consideration in the cost-effectiveness analysis is how to derate avoided capacity costs to account for operational constraints of the DR programs. Unlike the around-the-clock availability of a peaking unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

Some utilities account for these constraints of DR programs through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero to roughly 50 percent of the capacity value of the programs. The derate factor is program- and utility-specific.

In California, a methodology for establishing these derates has been codified by the CPUC in its DR Cost-Effectiveness Protocols.[14] There are effectively three factors that are used to adjust the avoided costs attributable to DR programs:

1. The “A Factor” represents the “portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted.” In other words, it accounts for limitations on the availability of the DR program, when DR events can occur, and how often.

small C&I, agricultural pumping load control, and technology-enabled PTR for residential and small C&I become moderately cost-effective. When the full incentive is counted as a cost, several DLC programs for residential and small C&I customers become slightly uneconomic. Across these cases, through the changes in the economics are relatively modest, with benefit-cost ratios that remain close to 1.0.

[14] California Public Utilities Commission, “2010 Demand Response Cost-Effectiveness Protocols,” December 16, 2010. http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC. An Energy Division Staff Proposal to update the protocols, dated June 2015, includes additional information on the derate factors and changes that are being considered: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=94268875

2. The "B Factor" accounts for notification time. Programs requiring day-ahead notification are less likely than programs with hour-ahead or real-time notification to coincide with system peak or reliability conditions due to forecasting uncertainty.

3. The "C Factor" accounts for limitations on any triggers or conditions that would permit the utility to call a DR event. For example, a DR tariff might only allow an event to be called if the outdoor air temperature exceeds some predetermined threshold.
4. Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE. The CPUC is currently examining the possible modification and expansion of these factors.

To develop derate factors for PGE, the derate factors applied by the California investor-owned utilities (IOUs) to their extensive portfolio of DR programs were compiled.[15] Based on a review of these derate factors, the values were calibrated to capture the appropriate relative relationships across the programs evaluated for PGE. Expert judgement was used to develop estimates for those programs for which there is not a clear example in the California data. This approach – starting with approved utility estimates from a nearby jurisdiction and modifying them to better reflect the programs that could be offered by PGE – ensures that the estimates are based on actual DR program experience and reasonably well tailored to PGE's system conditions. As a result, the avoided capacity costs were derated anywhere between 19 and 47 percent. A summary of the portion of avoided capacity cost attributed to each DR program is presented in Table 1.

15 See the links for the utility programs at the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

Table 1: Share of Total Avoided Cost Attributed to DR Program

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

Notes: A-factor estimates for dynamic pricing (PTR and CPP), residential DLC, and curtailable tariffs are derived from values estimated by the California utilities. A-factor estimates for other programs are based on intuitive relationships to those programs. B-factor estimates follow a general assumption observed in California that day-ahead programs have an 88% value and day-of programs have a 100% value. C-factor estimates in California tend to assume 100% for all programs except DLC, for which the assumption is 95%.

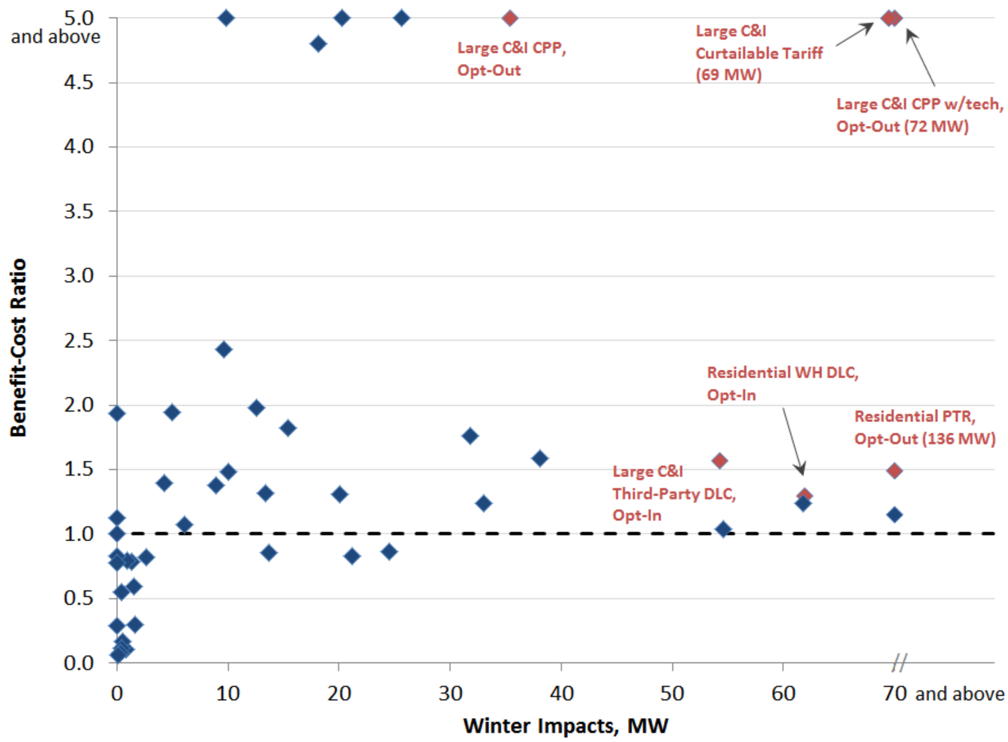
IV. Findings

The result of the analysis is an estimate of the maximum achievable peak reduction capability of each DR program for each year from 2016 through 2035, as well as a benefit-cost ratio for each program. These annual results are provided in Appendix D as a Microsoft Excel File. The results can be organized around 10 key findings:

1. The largest and most cost-effective DR opportunities are in the residential and large C&I customer segments
2. Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment
3. The incremental benefits of coupling enabling technology with pricing options are modest from a maximum achievable potential perspective and perhaps best realized through a BYOT program
4. BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term
5. Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits
6. EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand
7. Small C&I DLC has a small amount of cost-effective potential
8. DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a number of programs
9. Agricultural DR programs are small and uneconomic
10. The economics of some programs improve when accounting for their ability to provide ancillary services

Finding #1: The most cost-effective DR opportunities are in the residential and large C&I customer segments. In fact, nine of the ten programs with the largest potential are in the residential and large C&I sectors. Those also tend to be the sectors with the most cost-effective programs. Figure 3 below illustrates each program's cost effectiveness relative to its peak reduction potential. Those programs in the top-right portion of the chart provide the biggest "bang for the buck" whereas those in the bottom-left corner are small and uneconomic. The largest and most cost-effective programs tend to be pricing programs for residential and large C&I customers.

Figure 3: Winter Potential vs. B-C Ratio by Measure



Finding #2: Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment. If offered on an opt-out basis, residential PTR and CPP programs could potentially provide over 100 MW of peak reduction capability.[16] Offered on an opt-in basis, the potential is smaller but still in excess of 40 MW for both of these options. Impacts from TOU rates are smaller than those of PTR and CPP due to the lower peak period price in the TOU. However, the TOU impacts would represent a permanent shift in the daily system load profile due to the daily price signal embodied in the rate's design.[17] Based on the experience of recent pilot programs an opt-out BDR program could lead to peak demand reductions of close to 60 MW. However, given limited experience with BDR programs on a large scale, there is uncertainty around the extent to which the impacts would persist across multiple

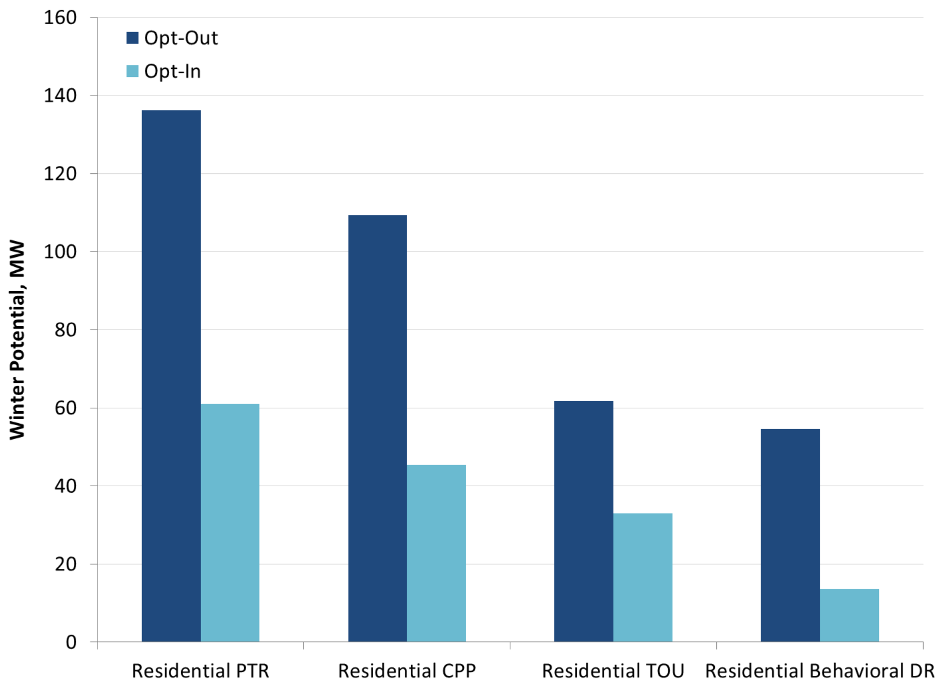
16 In this analysis, the higher potential in PTR relative to CPP is driven by the assumption that the PTR would have a significantly higher price ratio, and therefore produce larger per-participant load impacts. If the PTR and CPP were assumed to have the same price ratio, there would be more potential in a CPP rate offering.

17 It is also important to note that a TOU design could be coupled with a CPP or PTR rate. The TOU rate would apply most days of the year, with the CPP or PTR peak price (or rebate) applying on a limited number of days. This would provide both the daily load shifting benefits of the TOU rate and the advantages of a dynamic CPP or PTR price signal that can be dispatched in response to changing system conditions.

events and when deployed to all customers in PGE's service territory. There is significantly more certainty and reliability in the impacts of the pricing programs.

Figure 4 summarizes the potential estimates of residential pricing programs. All of these impacts are in the absence of enabling technology – they are purely based on behavioral response to the new prices and information. Additionally, it should be noted that the pricing options likely could not begin to be rolled out to customers on a full-scale basis until 2018 or 2019 due to constraints with the current billing system. While this would still leave time to reach significant enrollment levels by 2021, it means that the pricing options will not be available to address immediate needs for load reductions.

Figure 4: Winter Peak Reduction Potential for Residential Pricing and BDR



The programs are cost-effective in all cases except opt-in BDR.[18] For conventional pricing programs the opt-in offering has a slightly higher benefit-cost ratio than the opt-out offering due to marketing and education costs that are lower on a dollars-per-kW basis. However, opt-out offerings provide greater net benefits in absolute dollar terms. In all cases, the cost of AMI is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

[18] It is unlikely that BDR would be offered on an opt-in basis in any case. These programs are typically based on mass appeals to customers to reduce load, and customers could elect to opt out of the notifications if they desired.

Finding #3: The incremental benefits of coupling enabling technology with residential pricing options are modest and perhaps best realized through a BYOT program. The provision of enabling technology such as smart thermostats only modestly increases the potential of pricing options in the aggregate. On its surface, this appears counterintuitive because recent studies have found that enabling technology provides a 90 percent boost over the impact of price alone for a given customer, almost doubling their price responsiveness. The reason for the low incremental potential is that the eligible market for the technology is limited. We have assumed that only customers with both electric heat and central A/C would be eligible for pricing with enabling technology, as these are the only segment for which it is likely to be cost-effective given PGE's dual peaking nature and the need for load reductions in both the summer and winter seasons. Less than 10 percent of residential customers have both electric heat and central A/C. As a result, in the aggregate, potential increases only by about 5 MW for opt-in offerings and 10 MW for opt-out offerings.

Further, the provision of enabling technology by PGE does not appear to be incrementally cost-effective. Assuming there is already a plan to roll out dynamic pricing to customers, the incremental load reduction capability provided by enabling technology, above and beyond the impact that would be achieved in the absence of the technology, is not enough to justify the cost. This is a different outcome from some other jurisdictions, where a summer peak and significant air-conditioning market penetration can help to justify the investment.

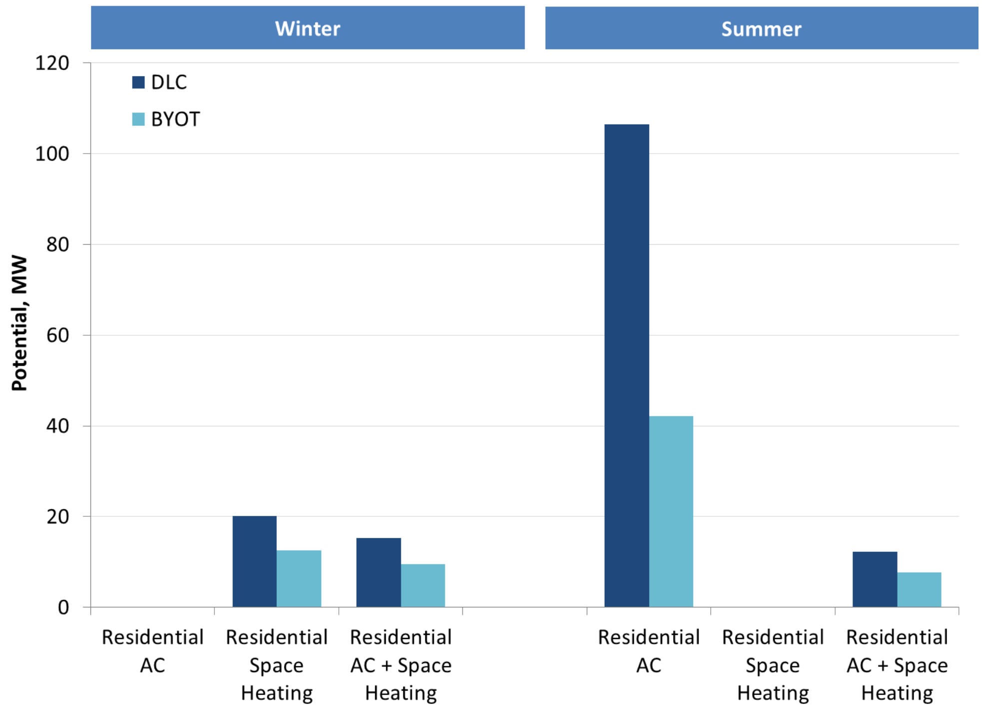
This conclusion changes when customers already own a smart thermostat; a BYOT program coupled with a dynamic pricing program could be highly cost-effective. In the future there may also be additional value in a "prices-to-devices" concept with real-time pricing and end-uses that provide automated response to changes in the price with short notification, as these programs could provide significant energy and even ancillary services benefits, in addition to avoided capacity costs. Additionally, the provision of enabling technology has the potential to improve customer satisfaction and participation in the programs by automating load reductions and allowing customers to "set it and forget it."

Finding #4: BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term. As is illustrated in Figure 5, A/C load control is a particularly large summer resource, representing over 100 MW of peak reduction capability. Potential is significant but smaller in the BYOT program, because it will take time for adoption of smart thermostats to materialize in the market. However, BYOT programs offer better cost savings than conventional DLC because there is no associated equipment cost. Whereas the benefit-cost ratio of conventional A/C DLC is around 1.1, the benefit-cost ratio of a BYOT A/C program is close to 2.0.[19] A program design consideration, therefore, will be whether to pursue the larger potential in the conventional DLC program versus the most cost-effective potential in

[19] Note that A/C load control in either form will become increasingly cost-effective as summer capacity needs escalate in PGE's service territory.

the BYOT program. The potential for differences in customer satisfaction with the programs is also an important consideration – this could be tested further through primary market research.

Figure 5: Seasonal Peak Reduction Potential for Residential DLC

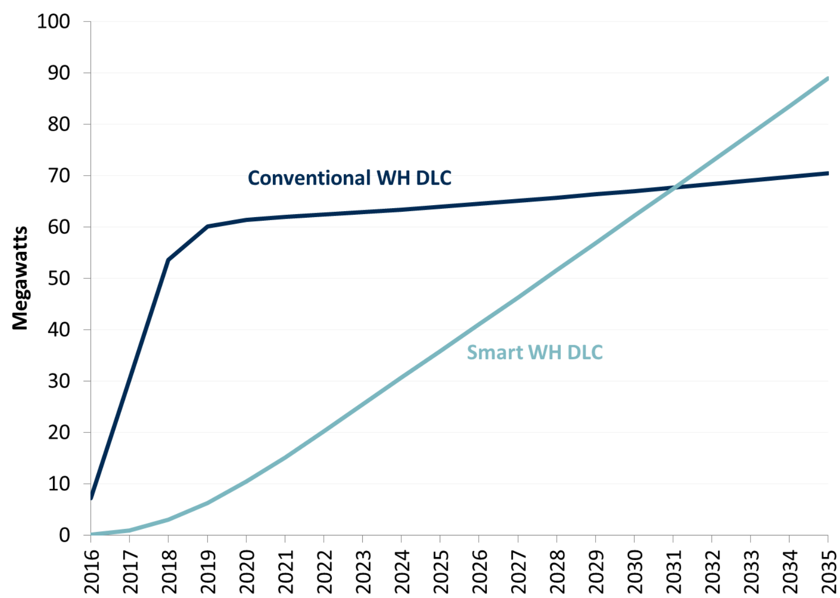


DLC programs are typically offered as part of a bundled package targeting multiple end-uses. Customers could receive different incentive payments based on the number of end-uses (A/C, space heating, electric water heating) they enroll in the program. Both the conventional DLC approach and the BYOT approach are cost-effective as bundled packages, with the conventional approach having a benefit-cost ratio of 1.3 and the BYOT approach having a ratio of 2.0. Additionally, for customers with an electric vehicle, EV charging load control could be added to the portfolio. In this case, the conventional approach would still be cost-effective, with a ratio of 1.2.

Finding #5: Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits. As described in Section 3, two types of water heating load control programs were modeled. The first is conventional water heating DLC. With this type of program, it is assumed that the control technology is a retrofit on existing or new water heaters. The typical equipment and installation costs would amount to approximately $300 per participant.[20] The second type of program is "smart" water heating DLC. This assumes that DR-ready water heaters continue to gain market share. In this scenario, costs are lower, with roughly $40 for equipment and installation (a communications module) and an incremental manufacturing cost to build in the DR capability of $25 per water heater.

Smart water heating DLC potential is low in early years of the forecast horizon due to limited market penetration of "DR-ready" water heaters. However, if these water heaters gain market share, potential in the program will increase. Eventually, due to likely higher participation rates among customers who invest in DR-ready water heaters, the potential could exceed that of a conventional DLC program. Figure 6 illustrates the annual winter peak reduction potential estimate based on one plausible trajectory of smart water heating market penetration.[21]

Figure 6: Winter Peak Reduction Potential for Water Heating Load Control



Both program options are cost-effective, although the smart water heating DLC program has a considerably higher benefit-cost ratio of 2.2, compared to 1.3 in the conventional program. This is because DR-ready water heaters offer a number of cost saving opportunities relative to conventional DLC, primarily in the form of reduced equipment and installation costs. Smart water heaters could also incorporate more sophisticated load control algorithms that provide

20 Cost assumptions for the water heating DLC analysis were derived from EPRI, "Economic and Cost-Benefit Analysis for Deployment of CEA-2045-Based DR-Ready Appliances," December 2014. Some costs were modified to be consistent with assumptions for other DR programs in this study.

21 Assumes 6% annual replacement of the existing stock of electric resistance water heaters, the assumed annual share of new water heaters that are DR-ready reaching 60% by 2022, and 25% of those customers participating in a water heating DLC program.

harder-to-quantify benefits. These algorithms could facilitate larger load reductions than a conventional on/off switch in the long run by anticipating the water heating needs of the owner and responding accordingly. This technology could also reduce the risk of insufficient hot water supply following a DR event relative to the conventional technology.

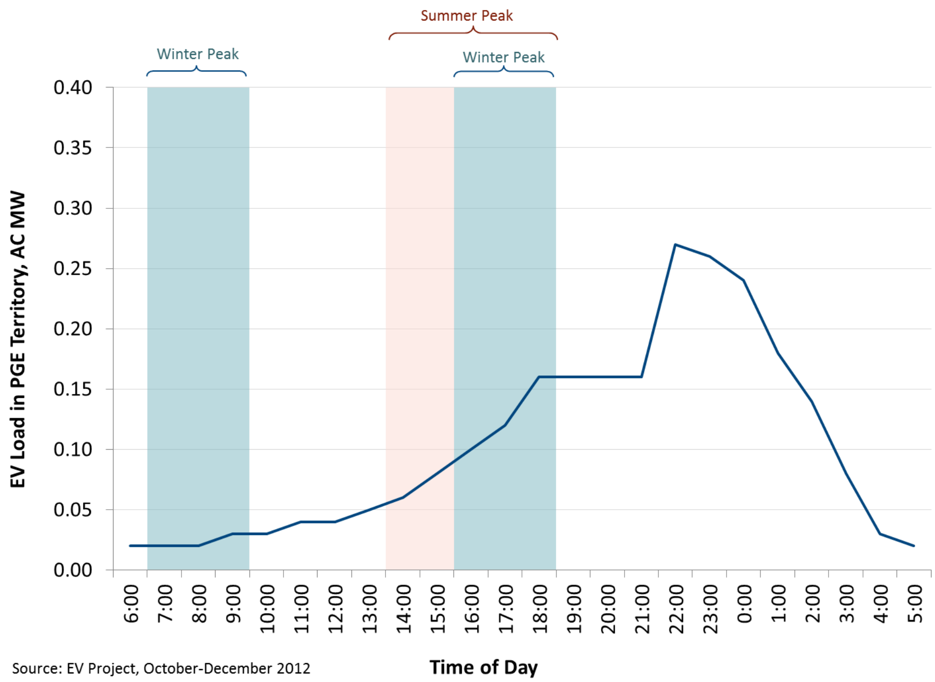
Ultimately, with water heating load control programs, benefits will vary depending on the load control strategy and the characteristics of the electric water heater. For example, if equipped with the appropriate control technology, electric resistance water heaters can provide significant increases and decreases in average load with very little notification, making them an ideal candidate to offer ancillary services.[22] Alternatively, or possibly in conjunction with this strategy, water heaters could be used as a form of thermal energy storage. Large tanks equipped with a mixing valve can super-heat the water at night and then require little to no additional heating during the day. This would be beneficial in a situation where the marginal cost of generating electricity is low or even negative at night (e.g., large amounts of nighttime wind generation coupled with inflexible baseload capacity) or when energy prices are high during the day; it provides an energy price arbitrage opportunity. The potential to provide this type of energy price arbitrage is highly dependent on the size of the water heater and the number of hours over which the load shifting is occurring.

Finding #6: EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand. Most residential charging occurs during off peak hours. Figure 7 illustrates the average EV charging load profile across many EV owners. While any individual owner's charging load would likely be concentrated in a smaller number of hours, the average load profile is the relevant profile to use in this study, because it represents the load shape that would be associated with a number of DR program participants with naturally diverse charging patterns across the service territory. As shown in the figure, the average amount of peak-coincident load available to curtail on a per-participant basis is less than 0.2 kW. As a result, even if most or all of the charging load can be shifted away from the peak hours, the low peak reduction potential translates into small benefits relative to the cost of the charging control equipment and the program is not cost-effective on a standalone basis. Total load reduction capability in the program is less than 2 MW by 2021 and less than 8 MW by 2035.[23]

[22] The technology that would facilitate this type of operation is in development and has been proven through a number of demonstration projects. It would include a potentially significant additional incremental cost beyond the costs modeled in this study.

[23] Assumes roughly 140,000 personal EVs in PGE's service territory by 2025.

Figure 7: Average Hourly Home Charging Profile of EV Owner



Source: EV Project, October-December 2012

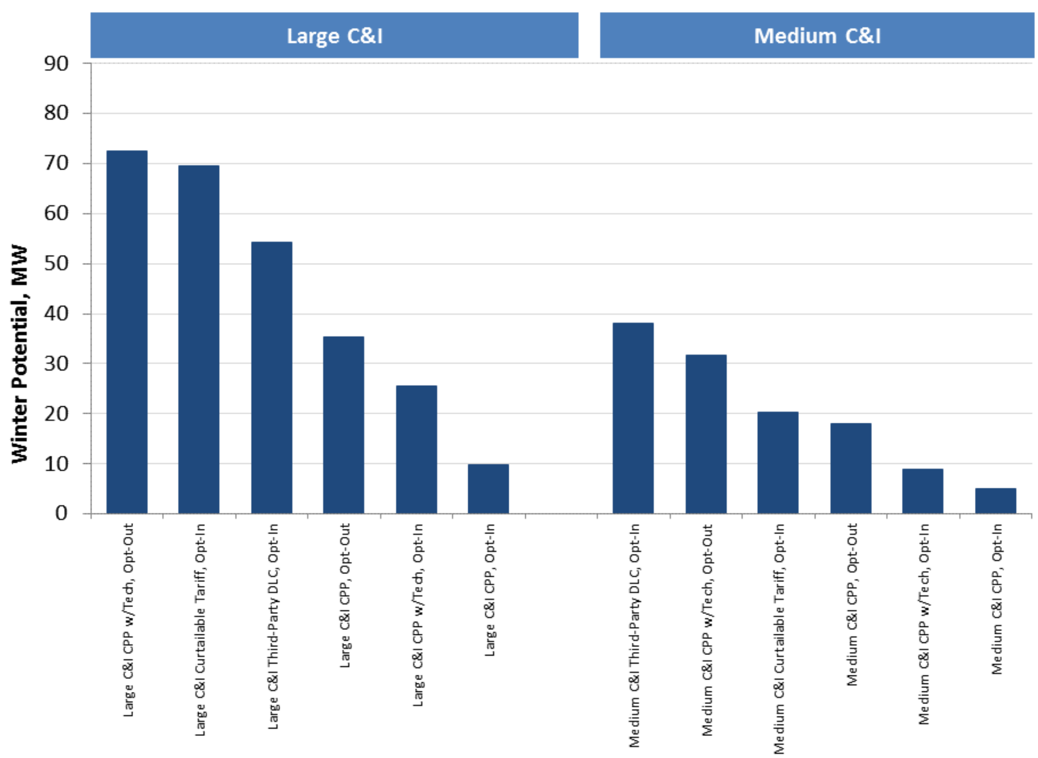
There are several important considerations to be aware of when interpreting these results, however. DR potential would be higher if targeting the late evening period with the most charging load; his time period could in fact eventually be the target of future DR programs that are designed to address distribution feeder-level constraints that are peaking at that time. The potential could also be higher in the future if EV owners adopt high-speed chargers that concentrate a larger amount of load in a smaller number of hours. It is also possible that there is more potential in programs focused on charging load outside the home. For example, the economics of load control at public charging stations might be more cost-effective. Control of commercial vehicle charging could also be cost-effective as part of a broader load control strategy, perhaps integrated with an Auto-DR program. Finally, as noted earlier in this section of the report, when EV charging load control is included as part of a broader DLC program, the package as a whole is cost effective.

Finding #7: Small C&I DLC has a small amount of cost-effective potential. Space heating DLC is the only cost-effective measure identified for the small C&I segment and its potential is small (around 6 MW in the winter). This is partly because small C&I customers tend to be unresponsive to time-varying rates unless equipped with enabling technology. Generally, electricity costs are a small share of the operating budget for these customers and they lack the sophisticated energy management systems of larger C&I customers. Further, while there is some potential in technology-enabled options, these customers have historically tended to be less likely to enroll in a DR program and generally represent a small share of the total system load.

Finding #8: DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a variety of programs. All of the analyzed DR programs are cost-effective for medium and large C&I customers. Customer acquisition costs tend to be lower on a dollars-per-kilowatt basis for these segments, leading to improved economics for DR. The large C&I segment accounts for the majority of the DR market in other regions of the U.S. for this reason.

In addition to being highly cost-effective, several large/medium C&I programs have large peak reduction potential. Figure 8 summarizes the potential in each DR option. There is significant potential in a curtailable tariff and a third-party DLC program. A CPP rate would provide similarly large impacts. In general, these programs could be considered the "low hanging fruit" of the available DR options.

Figure 8: Winter Potential for Medium and Large C&I DR Programs



Finding #9: Agricultural DR programs are small and uneconomic in PGE's service territory. There are large irrigation load control programs in the Pacific Northwest, such as Idaho Power's Irrigation Peak Rewards program. However, PGE has little irrigation pumping load. Relative to other options, programs focused on agricultural customers are small and not cost-effective in PGE's service territory. While pumping load control could become slightly cost-effective if PGE were to become a more heavily summer peaking utility, it is still too small to be considered a top priority given the other DR opportunities that exist.

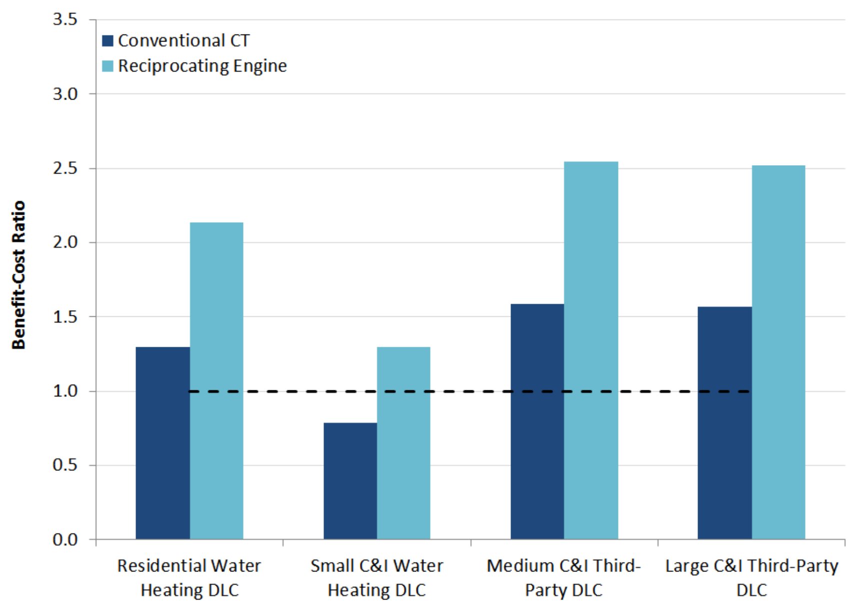
Finding #10: The economics of some programs improve when accounting for their ability to provide ancillary services. There is emerging interest in the Pacific Northwest in DR programs that can provide load reductions on very short notice in response to fluctuations in supply from intermittent generation resources like wind and solar. DR options that can provide both load decreases and increases provide even more value to the grid as ancillary services.

Since there is not currently an ancillary services market in the Pacific Northwest, the avoided cost of a reciprocating engine was used as a proxy for the value associated with these "fast" DR options. Reciprocating engines are more expensive than a conventional combustion turbine, but also have more operational flexibility and are better suited to address some of the reliability challenges posed by intermittent sources of generation.

Benefit-cost ratios were recalculated for those options capable of providing fast response (i.e., only DR options relying on automating technology). While the reciprocating engine is a good first-order approximation of this additional value, there are limitations to this approach and more granular analysis of the ancillary services value of the DR options would be informative in future research activities. Further, it should be noted that this cost-effectiveness analysis is based on the full coincident peak reduction capability of the programs; in practice, they would not be able to provide a reduction of that magnitude at regular intervals as an ancillary service, and the economics could change accordingly.

With a reciprocating engine as the basis for avoided costs, the economics improve for all programs and small C&I water heating DLC becomes cost-effective. Mass market water heating load control and medium and large C&I load control could provide fast ramping capability in the form of load increases and decreases, and would be particularly valuable as sources of ancillary services. Figure 9 illustrates the cost-effectiveness of these DR programs.

Figure 9: Cost-effectiveness for measures with "fast" load decrease and increase capability



V. Considerations for Future DR Offerings

This study utilized a detailed bottom-up approach to estimating PGE's peak demand reduction potential through DR programs. These estimates were carefully tailored to PGE's system conditions through research on likely adoption rates, per-customer impacts that are consistent with the experience of utilities around the country including the Pacific Northwest, and market conditions that are consistent with PGE's projections. The market potential for a variety of DR options and the economics of these options were assessed under a range of assumptions. The findings of the study suggest several considerations for future DR offerings by PGE.

Run a new dynamic pricing and behavioral DR pilot. A new pilot could provide insight about relatively untested issues such as the impact of a PTR in PGE's service territory, persistence in behavioral DR impacts, the relative difference in seasonal impacts of these programs, and even the difference in impacts when the rates are offered on an opt-in versus default basis. A pilot could also be designed to test a "prices-to-devices" concept involving real-time prices and automated response from specific end-uses, to address fluctuations in supply from renewable generation.

Develop a water heating load control program. There is a clear economic case for water heating load control and the potential benefits are diverse. Piloting or even a larger scale program would help to identify optimal load control strategies and further test the technical feasibility.

Continue to pursue opportunities in the large and medium C&I sectors. DR potential in the large C&I sector can be cost-effectively achieved through curtailable tariffs, third-party programs, and pricing options. Which of these programs to pursue is largely a strategic question, as each have their advantages and disadvantages. To maximize the participation from this customer segment, it may be beneficial to eventually pursue all of the program options through a portfolio-based approach.

Establish well-defined cost-effectiveness protocols. There does not appear to be a well-established approach to analyzing the cost-effectiveness of DR programs in Oregon. For example, the appropriate treatment of incentives as costs and the methodology for establishing derate factors to account for operational limitations of DR programs are two areas in need of further discussion. Reviewing the approaches being used in other states and tailoring these to the specific needs of the Oregon utilities would be a productive starting point. Well-defined protocols should be established while developing utility DR portfolios and strategies.

Develop a long-term rates strategy enabled by PGE's AMI investment. The strategy should address important considerations such as whether to offer new rates on an opt-in or default basis, the advantages and disadvantages of CPP versus PTR, whether a demand charge or increased customer charge is needed to address emerging inequities in cost recovery due to growing market penetration of distributed energy resources, how to transition customers to the new rate options, and other such considerations.

Explore the distribution system value of DR. Recent initiatives in other states have highlighted that the distribution-level value of DR may be understated in current practices. Additional analysis of distribution system constraints and the potential to deploy DR locally to address these constraints would be a useful research activity.

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Appendix A:
Participation Assumptions

Estimating Maximum Achievable Enrollment in DR Programs for PGE

PRESENTED TO

Portland General Electric

PRESENTED BY

The Brattle Group
Applied Energy Group

THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind estimates of enrollment in potential new DR programs in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Participation rates shown in this presentation are "steady state" enrollment rates once full achievable participation has been reached; they are expressed as a % of eligible customers

Pricing Programs

We developed enrollment estimates based on an extensive review of pricing participation studies

The enrollment estimates are derived from a review of 6 primary market research studies and 14 full scale deployments:

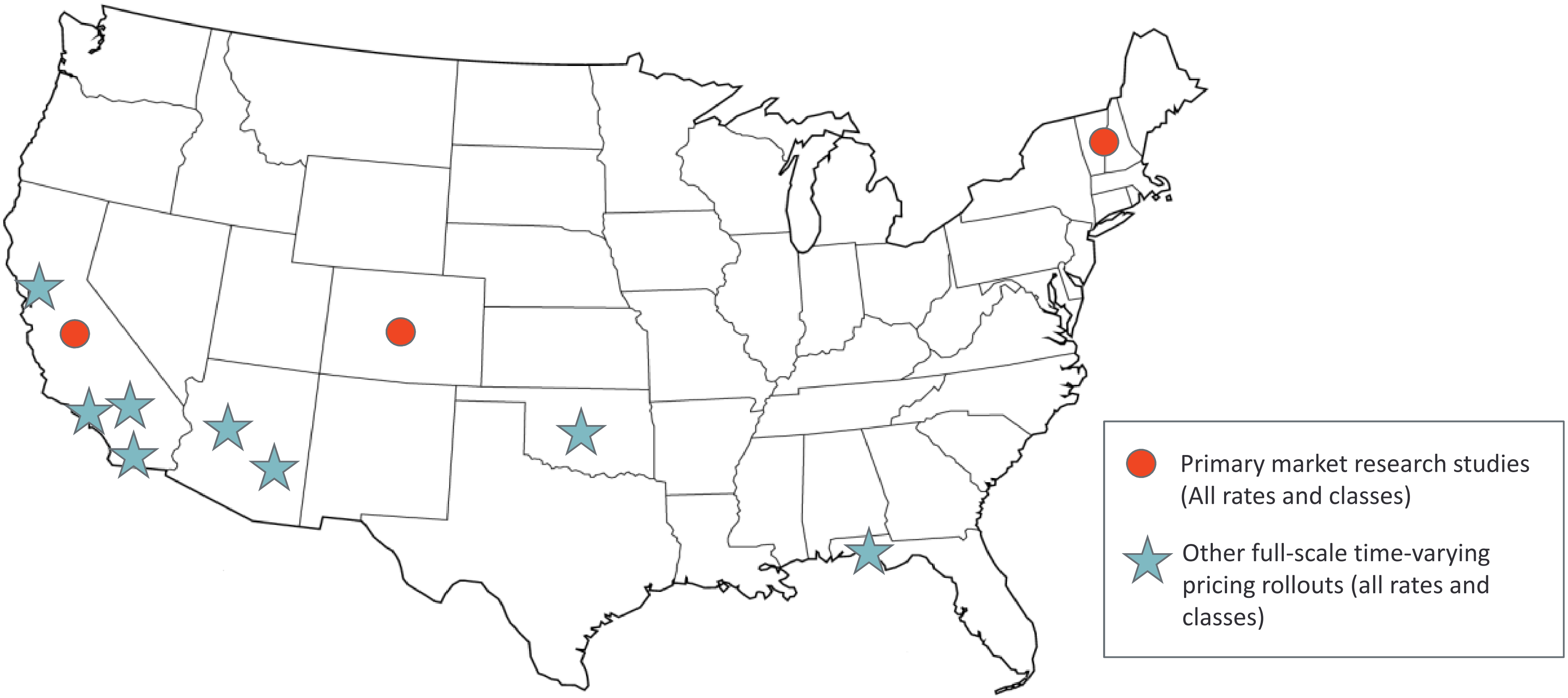
Primary market research studies

- A survey-based approach designed to gauge customer interest
- Adjustments were made to account for natural tendency of respondents to overstate interest in survey responses
- Respondents were randomly selected from utility customer base and confirmed to be representative of entire class
- Samples were large enough to ensure statistical validity of findings

Full-scale deployments

- Based on enrollment levels reported by utilities and competitive retail suppliers to FERC and other sources
- Restricted to programs with significant enrollment
- Focus on well marketed deployments

The market research studies and full-scale rate deployments span many regions of the U.S.



Additionally, our analysis includes the Ontario, Canada TOU rollout and three non-public market research studies in the Upper Midwest, Central Midwest, and Asia

Full-scale rate offerings have mostly been for residential and large C&I customers

Utility/Market	State/Region	Applicable class	Rates	Offering type	Approx. years offered
Arizona Public Service (APS)	Arizona	Residential	TOU	Opt-in	30+
Ontario Power Authority (OPA)	Ontario, CA	Residential	TOU	Opt-out	2
Salt River Project (SRP)	Arizona	Residential	TOU	Opt-in	30+
Gulf Power	Florida	Residential	CPP	Opt-in	14
Oklahoma Gas & Electric (OGE)	Oklahoma	Residential	CPP	Opt-in	2
Pacific Gas & Electric (PG&E)	California	Residential	CPP	Opt-in	3
Oklahoma Gas & Electric (OGE)	Oklahoma	Large C&I	TOU	Opt-in	?
Pacific Gas & Electric (PG&E)	California	Large C&I	CPP	Opt-out	3
San Diego Gas & Electric (SDG&E)	California	Large C&I	CPP	Opt-out	3
Southern California Edison (SCE)	California	Large C&I	CPP	Opt-out	3
Los Angeles DWP (LADWP)	California	All C&I	TOU	Opt-in	?
Progress Energy Carolinas	North/South Carolina	All C&I	TOU	Opt-in	15+

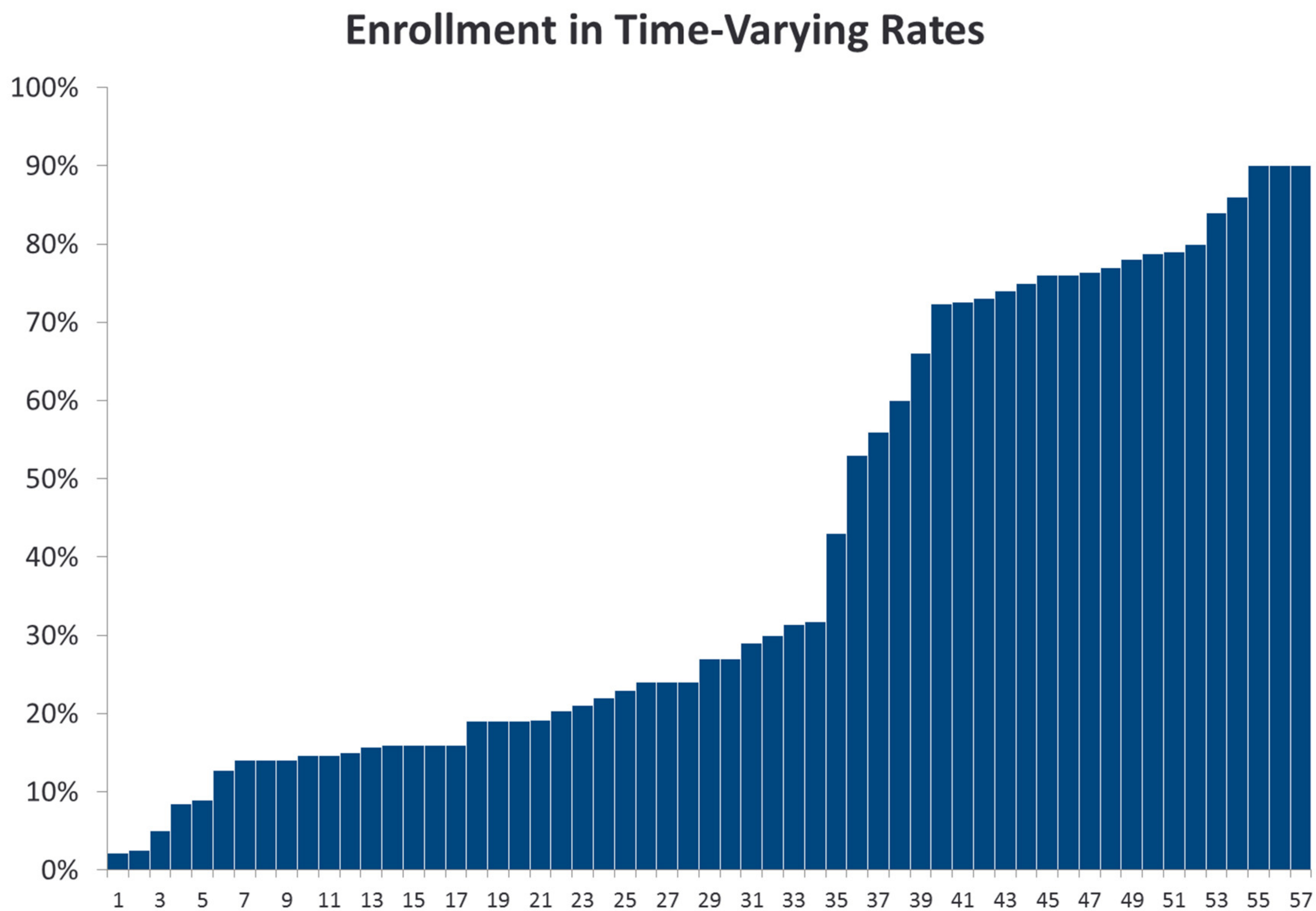
Notes:
BGE, Pepco, SDG&E and SCE have rolled out default PTR to their residential customers, but enrollment data is not available. Results are forthcoming.
The OPA TOU deployment is considered opt-out rather than mandatory because customers can switch to a competitive retail supplier.

The six market research studies primarily surveyed residential and small/medium C&I customers

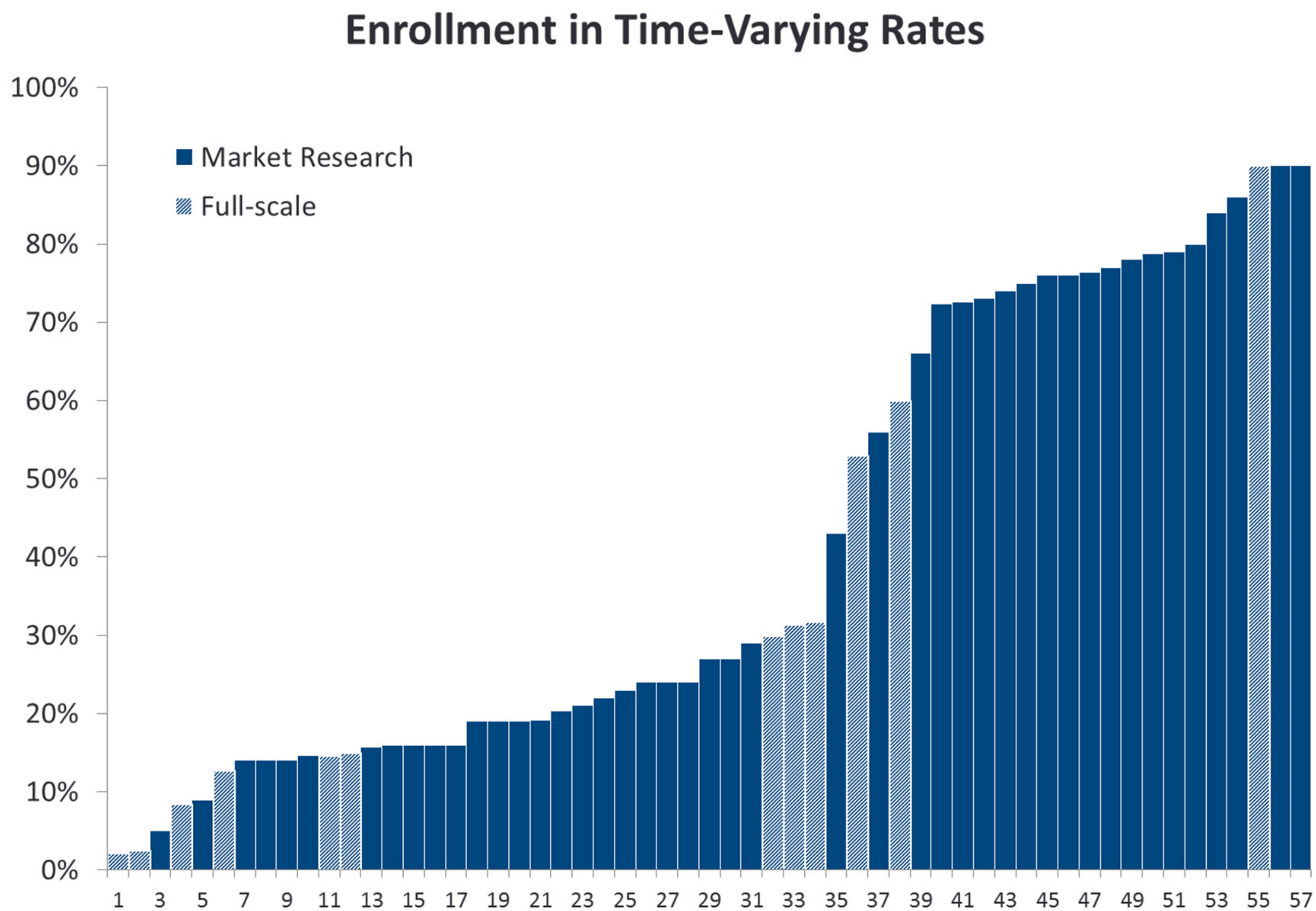
Utility/Market	Year of Study	Applicable classes			Rates	Deployment type	
		Res.	Small/Med	Large C&I		Opt-in	Opt-out
California IOUs	2003	X	X		TOU, CPP	X	X
ISO New England	2010	X	X		TOU, CPP, PTR, RTP	X	
Asian Utility	2013	X			TOU, PTR	X	
Large Midwestern IOU	2013	X	X	X	TOU, CPP	X	X
Mid-sized Midwestern Utility	2013	X	X		TOU, CPP	X	
Xcel Energy (Colorado)	2013	X	X	X	TOU, CPP, PTR	X	X

- These market research studies were conducted in order to form the basis for utility AMI business cases or DSM potential studies
- They were led by Dr. David Lineweber and a team of market researchers who are now with Applied Energy Group (AEG)

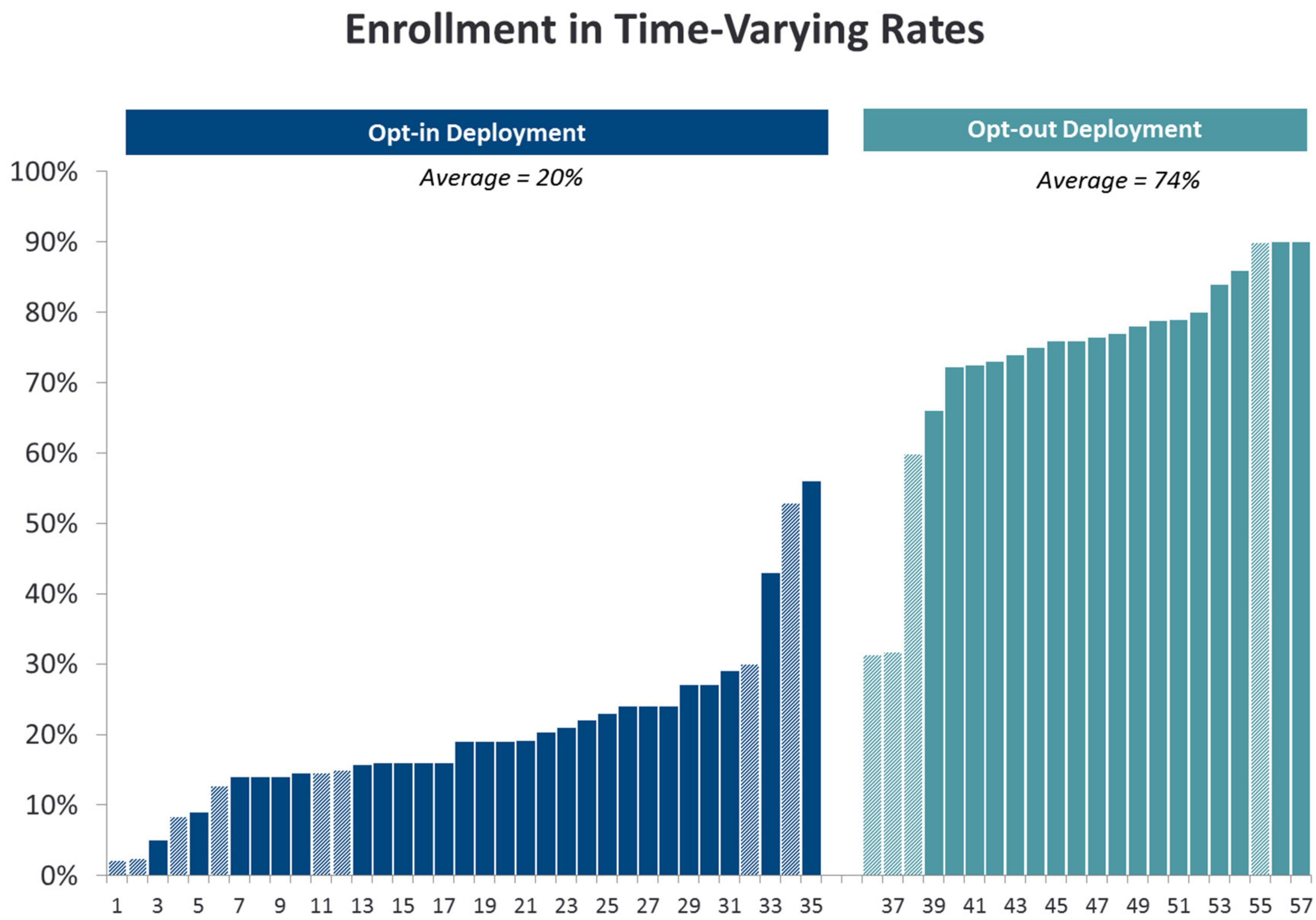
There are 57 enrollment observations across all of the studies (sorted low to high)



There is no obvious bias in market research results relative to full-scale deployments



Opt-out offerings result in significantly higher enrollment on average



The enrollment data can be further organized with additional granularity

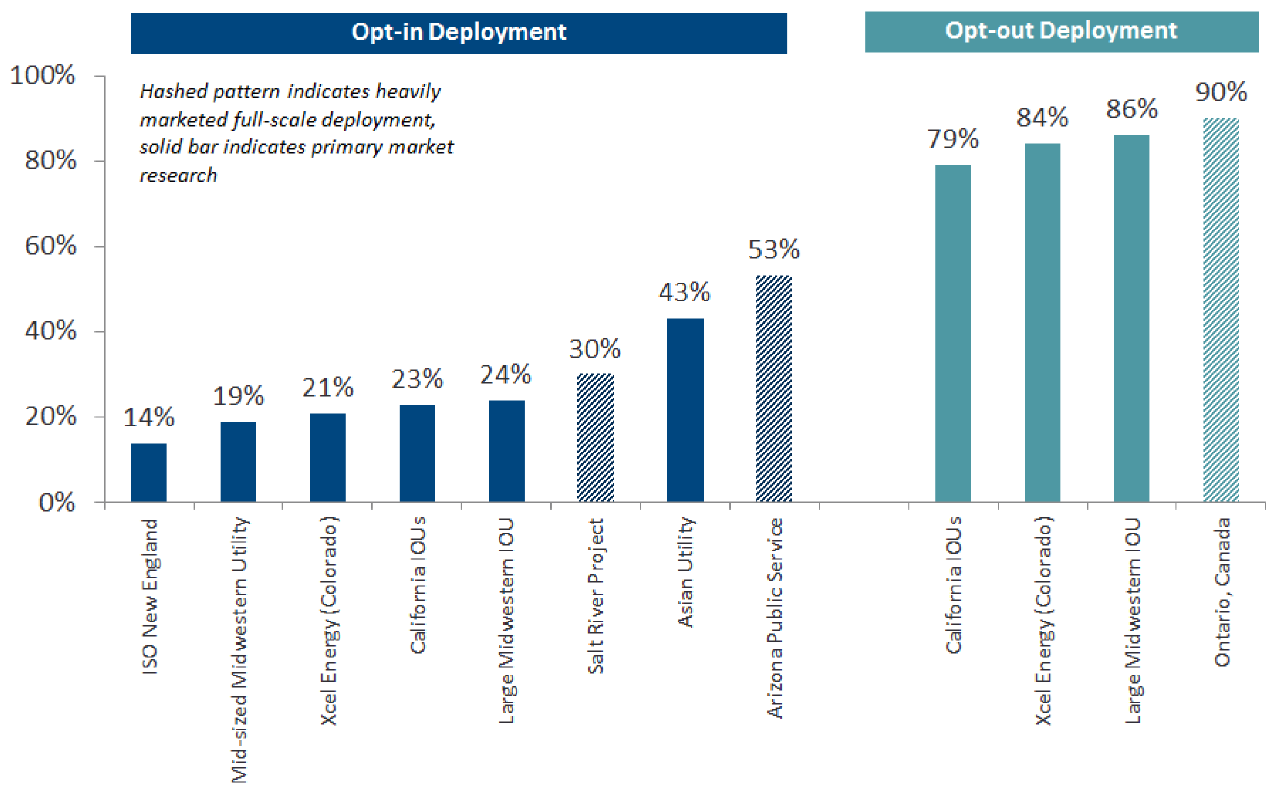
We have organized the data across the following elements

- Customer class (residential vs non-residential)
- Rate (TOU, CPP)
- Offering (opt-in vs opt-out)

We summarize the key findings of this comparison in the slides that follow

The results of our residential TOU analysis are summarized below

Residential TOU Enrollment Rates

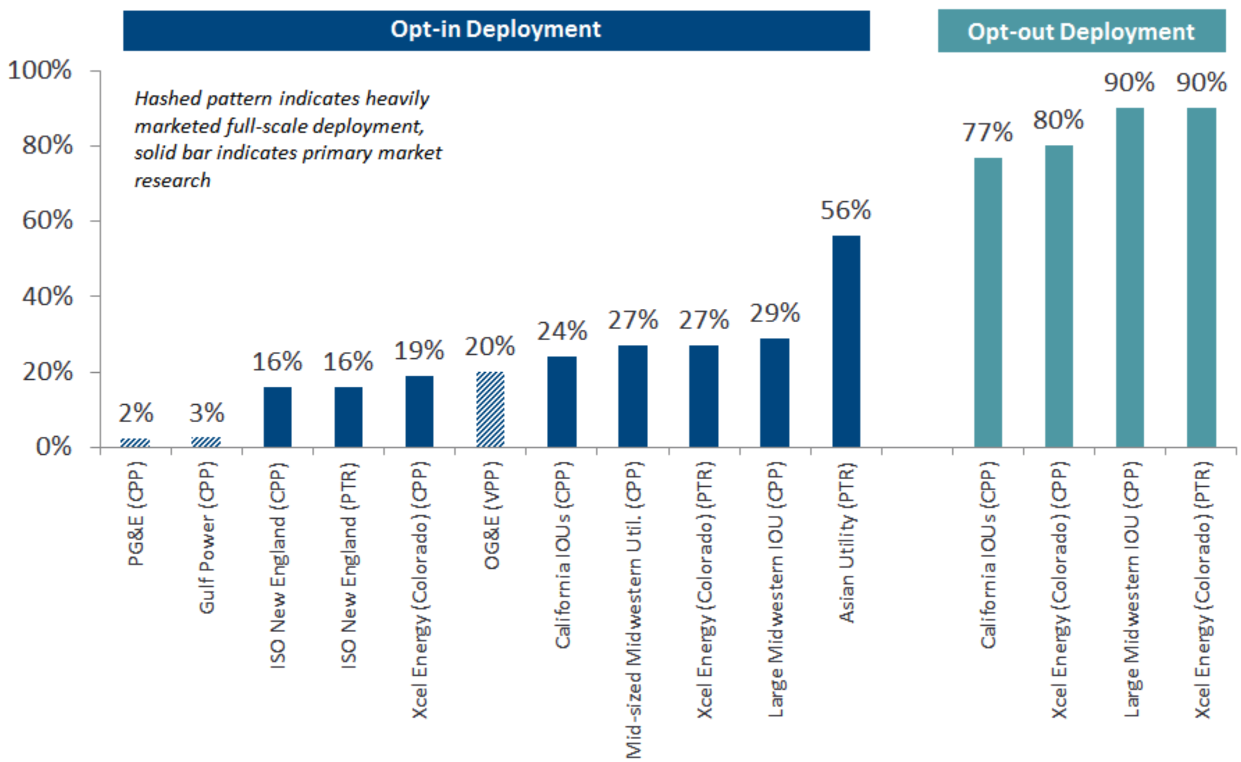


Comments

- Opt-in average = 28%
- Opt-out average = 85%
- Opt-out rate offerings are likely to lead to enrollments that are 3x to 5x higher than opt-in offerings
- Arizona's high opt-in TOU participation is attributable to heavy marketing as well as large users' ability to avoid higher priced tiers of the inclining block rate
- In Ontario, the 10% opt-out rate includes some customers who switched to a competitive retail provider even before the TOU rate was deployed

Residential dynamic pricing enrollment observations are similar to those of TOU

Residential Dynamic Pricing Enrollment Rates



Note: Pepco and BGE have deployed a default residential PTR. Results forthcoming.

Comments

- Dynamic pricing options considered include CPP, variable peak pricing (VPP), and peak time rebates (PTR)
- PTR enrollment is roughly 20% higher than CPP enrollment
- OG&E's VPP rate was rolled out on a full scale basis in 2012 and has reached its target enrollment rate of 20% a year ahead of schedule
- Availability of Gulf Power's CPP rate is limited
- Additionally, Pepco, BGE, SCE, and SDG&E have deployed a default residential PTR; results are forthcoming

Why are the full scale residential dynamic pricing enrollment levels slightly lower than the market research results?

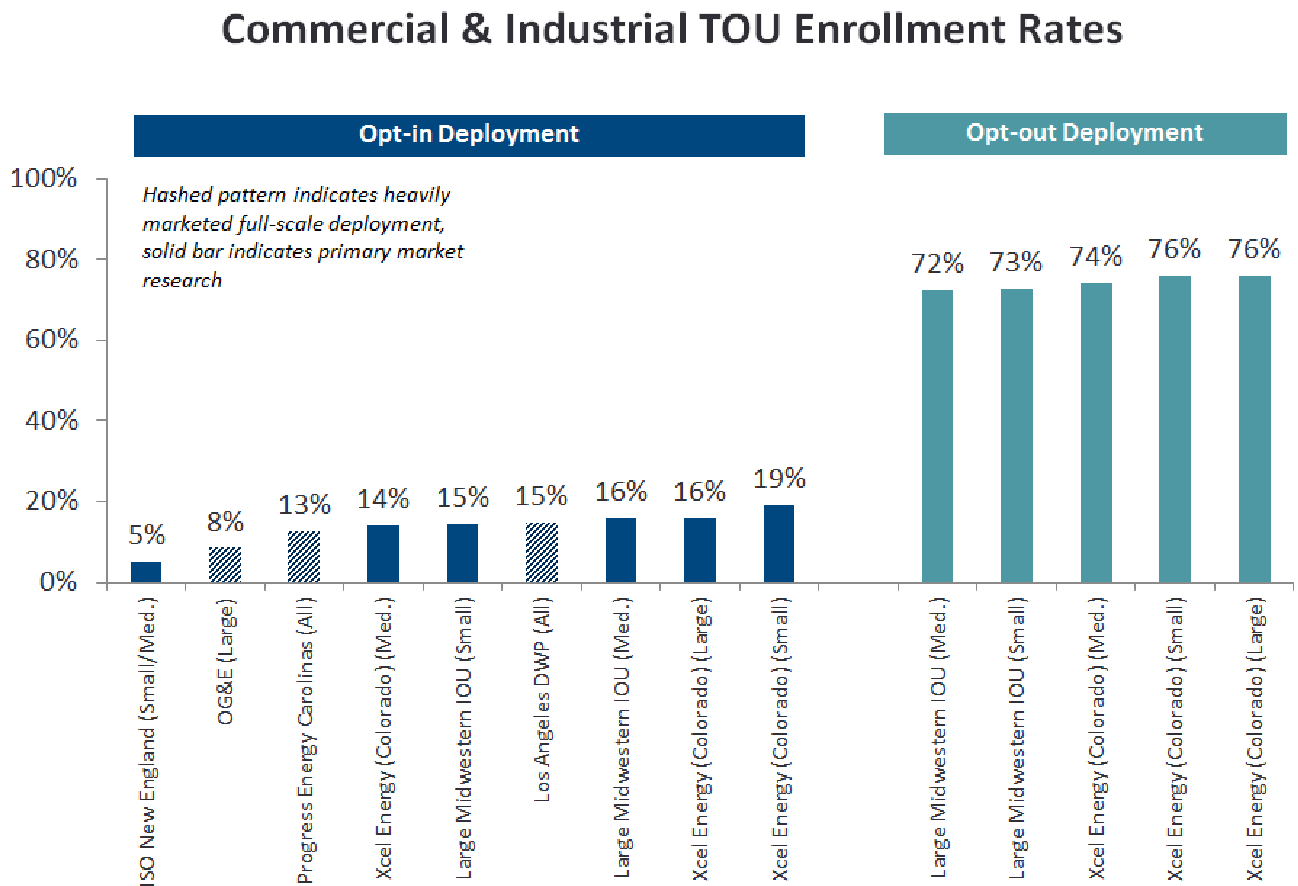
- The primary market research identifies all "likely participants" in the dynamic pricing rate, some of whom are very proactive and eager to sign up, while others would sign up but require more education, clear explanation, and additional outreach

- Most utility marketing budgets for dynamic pricing programs have been relatively low and are not designed to provide the type of outreach necessary to enroll customers falling in the latter category

- These customers represent untapped potential in the program and could likely be signed up with a more intensive marketing effort

- For example, heavily marketed utility energy efficiency programs with similar bill savings opportunities reach enrollment rates of 60%

C&I TOU enrollment levels are slightly lower than those of the residential class



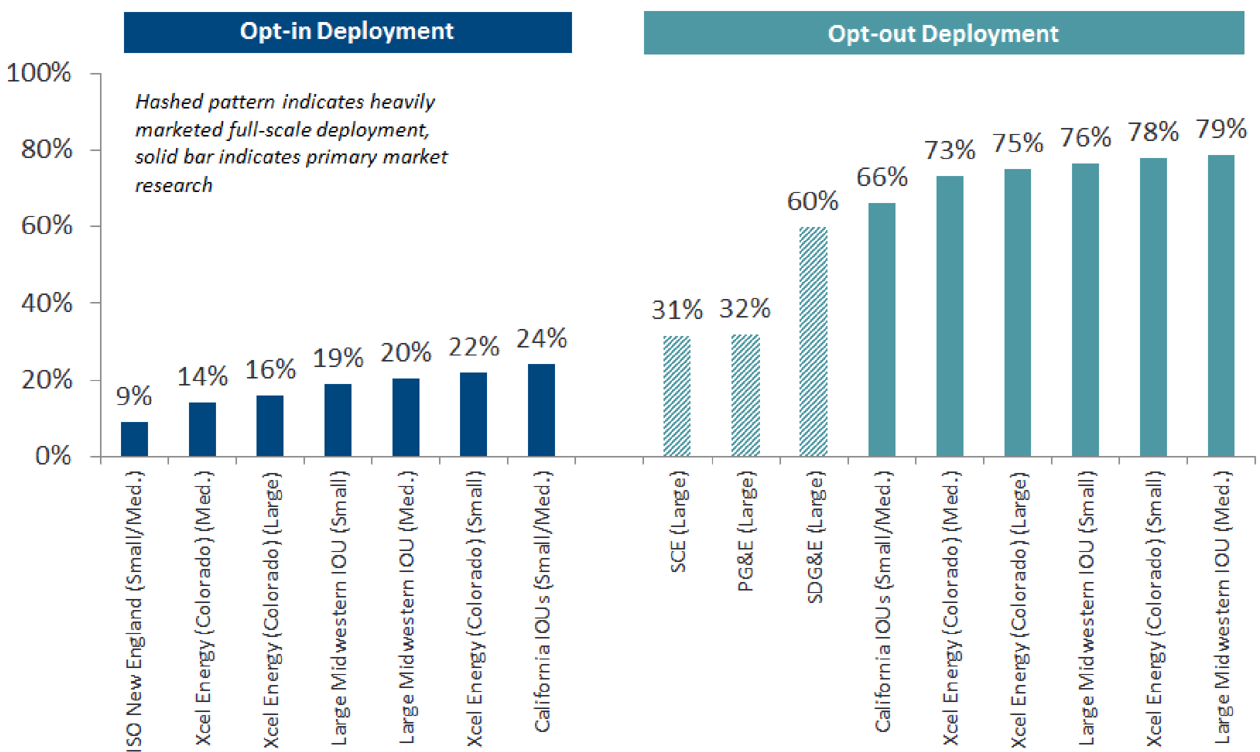
Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 13%
- Opt-out average = 74%
- Estimates are reported separately for Small, Medium, and Large C&I customers (as designated by the utility) where possible
- Full-scale opt-in deployment estimates were derived from FERC data, with a focus on the highest enrolled programs
- TOU rates are often offered on a mandatory basis to Large C&I customers; these are excluded from our assessment

There is limited full-scale CPP deployment experience for C&I customers

Commercial & Industrial CPP Enrollment Rates



Note: Size of applicable C&I customer segment indicated in parentheses.

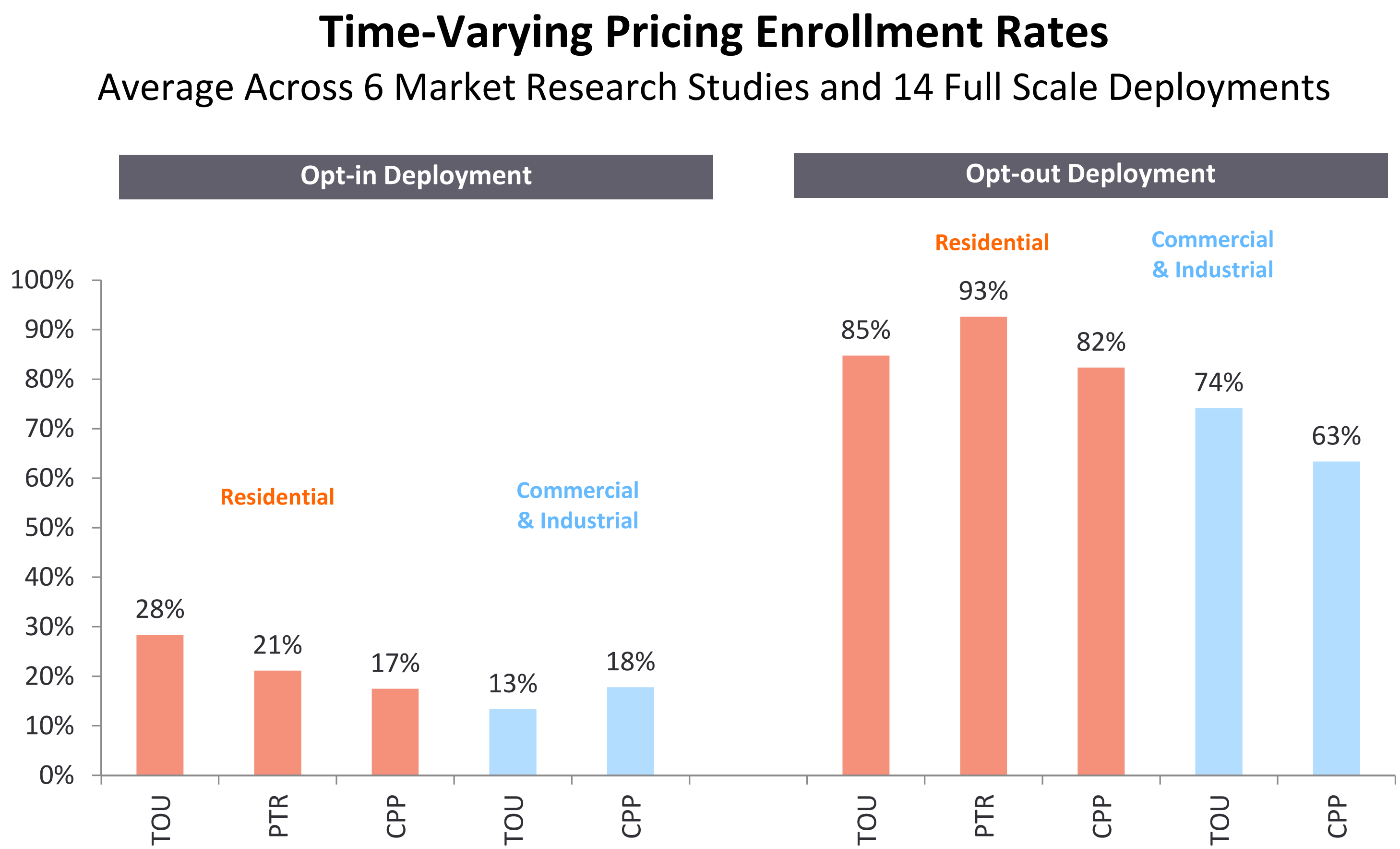
Comments

- Opt-in average = 18%
- Opt-out average = 63%
- C&I preferences for CPP rates tend to be slightly higher than for TOU rates – the opposite of the relationship observed among residential customers
- The California IOU default CPP offering began in 2011 and has experienced significant opt-outs - it may not have been effectively marketed. The rate is being deployed to smaller customers and further results are forthcoming

Preliminary conclusions can be drawn from our assessment, although further research and experience are needed

- Opt-out rate offerings produce enrollment levels that are between 3x and 5x higher than opt-in rate offerings
- Residential customers express a slightly higher likelihood to enroll in time-varying rates than small/medium C&I customers, both through market research and in full-scale deployments
- When offered in isolation, residential customers appear to have a slight preference for TOU over CPP; when offered as two competing rate options, more customers choose CPP
- Customers appear more likely to enroll in PTR than CPP
- Market research and full scale deployment results generally align well; in cases where full deployments produces lower enrollment estimates, it is likely that additional enrollment could be achieved through more focused marketing efforts

The results of our assessment can be averaged across the studies for each customer class and rate option



Offering enabling technology is likely to slightly increase participation among eligible customers

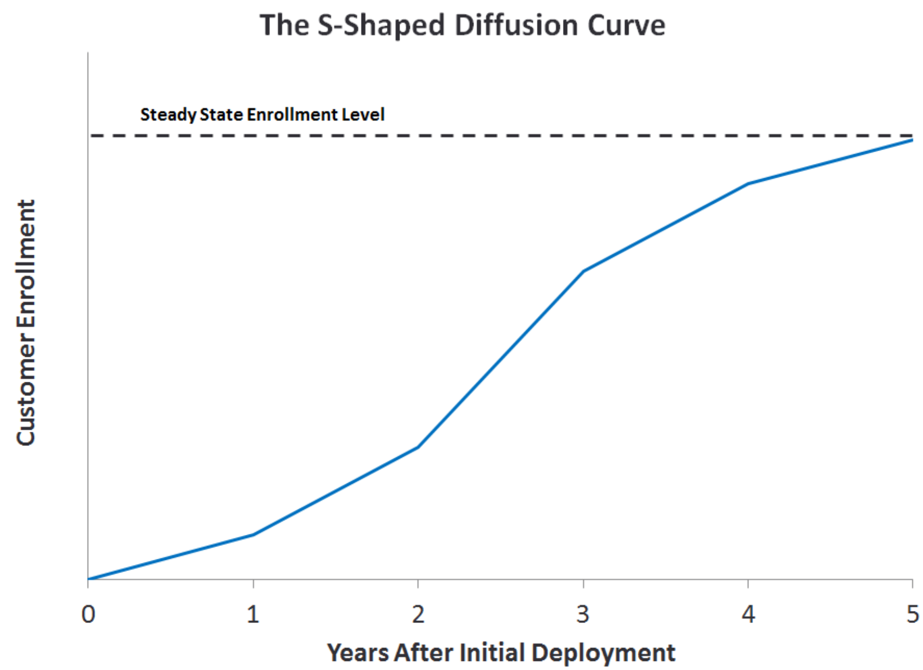
- For residential and small C&I customers, programmable communicating thermostats (PCTs) would automate reductions in air-conditioning load during critical peak periods
- For medium and large C&I customers, Auto-DR technology could be integrated with a facility's energy management system to automate load reductions during high priced periods of the CPP rates
- Market researchers have estimated that enrollment among tech-eligible customers will increase if they are also offered these technologies as part of the rate deployment
- **Opt-in enrollment among eligible customers is likely to increase by around 25% if offered enabling technology** (i.e., an enrollment rate of 20% would become 25% among tech-eligible customers)
- **For an opt-out rate offering, enrollment would likely increase by roughly 10%** (i.e. an enrollment rate of 80% would become 88% among tech-eligible customers)
- Large C&I customers are assumed to have more interest in Auto-DR than medium C&I customers due to a higher degree of sophistication in energy management capability

The proposed “steady state” enrollment rates

Class	Option	Opt-in	Opt-out
Residential	TOU - No Tech	28%	85%
Residential	CPP - No Tech	17%	82%
Residential	CPP - With Tech	22%	91%
Residential	PTR - No Tech	21%	93%
Residential	PTR - With Tech	26%	95%
Small C&I	TOU - No Tech	13%	74%
Small C&I	CPP - No Tech	18%	63%
Small C&I	CPP - With Tech	20%	69%
Small C&I	PTR - No Tech	22%	71%
Small C&I	PTR - With Tech	27%	78%
Medium C&I	CPP - No Tech	18%	63%
Medium C&I	CPP - With Tech	20%	69%
Large C&I	CPP - No Tech	18%	63%
Large C&I	CPP - With Tech	25%	69%

We account for a multi-year transition to the steady state enrollment levels

- Changes in participation are assumed to happen over a 5-year timeframe once the new rates are offered
- The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half
- A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options



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Non-Pricing Programs Included in Prior PGE Studies

Participation in non-pricing programs was updated using the most recent FERC data

FERC conducts a bi-annual survey of utility DR programs, including information on program impacts and enrollment

The 2012 PGE DR potential study enrollment estimates were based on data in the 2010 FERC survey, which was the most current information available at the time

FERC has since released the 2012 survey results and has discontinued the survey; information is now collected through EIA form 861, but with much less granularity

We have updated the enrollment estimates using the 2012 FERC survey

The 75th percentile of achieved enrollment is used as a "best practices" estimate

The FERC data provides a national distribution of actual enrollment in DR programs

To establish a "best practices" estimate of what could eventually be achieved through a new program, we use the 75th percentile of the distribution for each program type

The recent PacifiCorp DR potential study used the 50th percentile

However, since the purpose of our study is to estimate maximum achievable potential rather than the average participation rate, we recommend using the 75th percentile

We will acknowledge throughout the final report that the figures presented are estimates of maximum achievable potential rather than what is necessarily likely to occur, particularly in the short run given the relatively limited experience with DR in the Pacific Northwest

Updated estimates are fairly similar to those of the 2012 PGE potential study

Class	Option	PGE (2012)	PacifiCorp (2014)	PGE (2015)
Residential	DLC - Central A/C	20%	15%	**20%**
Residential	DLC - Space Heat	20%	15%	**20%**
Residential	DLC - Water Heating			**25%**
Small C&I	DLC - Central A/C	20%	3%	**14%**
Small C&I	DLC - Space Heat	20%	3%	**14%**
Small C&I	DLC - Water Heating			**2%**
Medium C&I	DLC - AutoDR	18%		**15%**
Medium C&I	Curtailable Tariff		24%	**20%**
Large C&I	DLC - AutoDR	18%		**25%**
Large C&I	Curtailable Tariff	17%	24%	**40%**

Note:
An average curtailable tariff participation rate of 30% for C&I customers was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's ISOC program)

In a couple of instances, we deviated from the 75th percentile assumption

Space heating DLC participation is assumed to be the same as air-conditioning DLC due to lack of better data

The 75th percentile participation rate of 30% for C&I customers in a curtailable tariff was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's highly subscribed "ISOC" program)

There is limited data available on Auto-DR adoption rates when deployed at scale; we have assumed that adoption would be similar to that of technology-enabled CPP for C&I customers, since it offers a similar financial incentive to manage load

New Non-Pricing Programs Not Included in Prior PGE Studies

We estimated participation rates for three new programs; two more are in development

Draft participation rates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Participation rates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- All assumptions for these two programs are being developed in parallel and in coordination with PGE staff

Enrollment in BYOD programs will be driven partly by the market penetration of smart thermostats

We have based our estimates of the eligible population for BYOD programs on projections of market deployment for communication-enabled thermostats

Research by Berg Insight projects that over 25% of homes in North America will be equipped with a 'smart system' by 2020, relative to 6% currently

CMO, and Adobe Company, reports that smart thermostats are expected to have over 40% adoption by 2020

Acquity Group's 2014 Internet of Things (IoT) survey reports that approximately 30% of consumers will adopt smart thermostats in the next 5 years

To be conservative, we use an assumption at the low end of this range

Source	Year	Market Penetration (%)
Berg Insight – N. America	2020	25%
CMO	2020	40%
Acquity Group – N. America	2020	30%

- We assume that smart thermostat market penetration in PGE's service territory will reach 25% of all homes by 2020
- The Energy Trust's interest in promoting smart thermostats could drive this estimate upward
- Additionally, rapid growth in central air-conditioning adoption in the Pacific Northwest relative to other parts of the country could lead to a future scenario that exceeds this estimate, as new A/C systems are installed with smart thermostats
- Note: Estimate could be refined further upon receiving the Navigant Research report on smart thermostats

Participation among eligible customers is likely similar to participation in conventional DLC programs

The BYOD program is assumed to be offered on an opt-in basis only

With a similar participation incentive as in the conventional DLC program, we assume that participation in the BYOD program would be similar to but slightly higher than that of the conventional DLC program

The intuitive reasoning for this is that customers who purchase a smart thermostat are more likely to be conscious about their energy usage and keen on using the features of their new device

To capture this, we estimate that participation in BYOD programs to be 25%, which is 5% higher than in DLC programs

We have modeled Behavioral DR both on an opt-in and an opt-out basis, similar to pricing programs

Behavioral Demand Response is essentially a peak time rebate (PTR) program without the accompanying financial incentive to reduce consumption during event hours

The no-incentive, no-risk nature of BDR programs could make customers slightly less likely to opt-in and slightly more likely to opt-out

To establish the BDR participation rates, we start with the PTR participation rates discussed previously in this presentation, and make adjustments to the share of customers that opt-in and opt-out

Three sources suggest that BDR participation could resemble that of a PTR program

OPower estimates that customer adoption of their opt-out BDR programs is upwards of 90%

Green Mountain Power (2012-2013)

- Recruitment strategies used a combination of mail, web and phone
- Participation in the opt-in, notification-only program achieved a 34% participation rate

MyMeter Program (four electric co-ops in Minnesota)

- Opt-in participation rates range from 9% to 16% per co-op, with more weight toward the high end of the range

Research supports a 20% opt-in and a 80% opt-out participation rate

Utility/Program	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
OPower BDR program adoption rate		90%
Green Mountain Power	34%	
MN electric co-ops (MyMeter Program)	9-16%	

- In both the opt-in and opt-out deployment scenarios, we choose fairly conservative participation rates relative to the data that is available on BDR enrollment
- This is in recognition of the long-term uncertainty in enrollment in these programs and the fairly small scale at which the existing pilots were conducted

Irrigation Load Control Programs typically target large irrigation & drainage pumping systems

Many utilities, such as SCE, Entergy Arkansas, and Idaho Power focus on large customers

The 2014 PacifiCorp potential study sets the eligibility threshold at customers with pumps 25 HP and higher, representing 78% of total agricultural load

We propose that the eligible population be limited to customers on Schedule 49

- Comprises Irrigation & Drainage Pumping customers with loads >30 kW
- These customers represents about 75% of total Irrigation and Drainage load (based on PGE's February 2015 Rate Case Filing)

There are a few data points upon which to base PGE's irrigation DLC participation estimate

EnerNOC's 2013 Irrigation Load Control Report provides enrollment estimates for Rocky Mountain Power

- The Utah service territory had a participation rate of about 20% of eligible load, whereas the Idaho service territory had participation of 48% of eligible load
- All irrigation customers were eligible to participate
- Customers with loads <50 kW required to pay an enablement fee

Idaho Power has achieved significant enrollment

- Conversations with Idaho Power staff indicate that roughly 10% of irrigation customers are enrolled
- These participants are significantly larger than average, representing peak reduction capability of 39% of system peak coincident irrigation load

The recent PacifiCorp DSM potential study suggested a lower participation rate for Oregon

- Participation in California, Oregon, Washington, and Wyoming assumed to be 15% of eligible load, based on PacifiCorp program experience
- Assumed participation rates for Idaho and Utah were significantly higher, likely reflecting the different nature of the crops in those two states, leading farmers to be more likely to allow more regular curtailments to their irrigation cycle

There is support for a 15% participation rate assumption for Irrigation Load Control programs

Utility/Program	Opt-In Participation Rate (% eligible load)
PacifiCorp 2015 (CA, OR, WA, WY)	15%
RMP 2013 (Utah)	20%
Idaho Power	39%
RMP 2013 (Idaho)	48%

- The range of participation rates observed in existing programs is wide
- We have chosen an estimate on the low end of the range to avoid overstating participation that may be associated with hotter, drier climates like those of Idaho and Utah
- This assumption has the added benefit of being consistent with the Oregon assumption in the PacifiCorp potential study

Summary of Participation Assumptions for New Non-Pricing programs

Program	Eligible Population in 2020 (%)	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
BYOD	25% of Residential Customers	25%	N/A
Behavioral DR	100%	20%	80%
Irrigation Load Control	75% of Irrigation Customers	15%	N/A

Sources for new non-pricing participation assumptions

- Acquity Group, The Internet of Things: The Future of Consumer Adoption, 2014.
- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015.
- Berg Insight, Smart Homes and Home Automation, January 2015.
- CMO, 15 Mind-Blowing stats about the Internet of Things, April 17, 2015.
- Edison Institute, Innovations Across the Grid, Volume II, December 2014.
- EnerNOC, 2013 PacifiCorp Irrigation Load Control Program Report, March 3, 2014.
- Honeywell, Structuring a Residential Demand Response Program for the Future, June 2011.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- R. Kiselewich, The Future of Residential Demand Response: BGE's Integration of Demand Response and Behavioral, E Source Forum 2014, September 29 - October 2, 2014.
- S. Blumsack and P. Hines, Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013, March 5, 2015.

Appendix B:

Per-Participant Load Impact Assumptions

Estimating Per-Participant DR Impacts for PGE

PRESENTED TO

PGE

PRESENTED BY

Ahmad Faruqui
Ryan Hledik
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THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind our estimates of per-participant peak demand reductions for DR programs that could be offered in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Note that the impacts in this presentation are per average participant; they are not multiplied into participation rates to arrive at estimates of system-level impacts

Pricing Programs

Pricing impact estimates have undergone a significant overhaul relative to the 2012 study

Incorporated new findings of 24 pilots and full-scale rollouts that have occurred since the 2012 study, including the DOE-funded consumer behavior studies

Modified the impact estimation methodology to take advantage of the greater number of data points that are now available

- Differentiation in price responsiveness between TOU, CPP, and PTR rates
- Accounting for difference in average response under opt-in versus opt-out deployment
- Improved differentiation between winter and summer impacts

The following slides provide a step-by-step description of our approach

First, we established a reasonable peak-to-off-peak price ratio for each rate option

The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates

A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result

Price ratios are based on rate designs that have recently been offered by PGE or are currently under consideration

- TOU: 2-to-1
- CPP: 4-to-1*
- PTR: 8-to-1*

* Rate designs were provided by PGE. It would alternatively be useful to explore CPP and PTR rates with consistent price ratios.

Impacts of time-varying rates were then simulated based on a comprehensive review of recent pilot results

PGE has recently conducted a CPP pilot and previously conducted a TOU pilot; the results are incorporated into our analysis, but have been supplemented with findings from dynamic pricing pilots across the globe to develop more robust estimates of price response

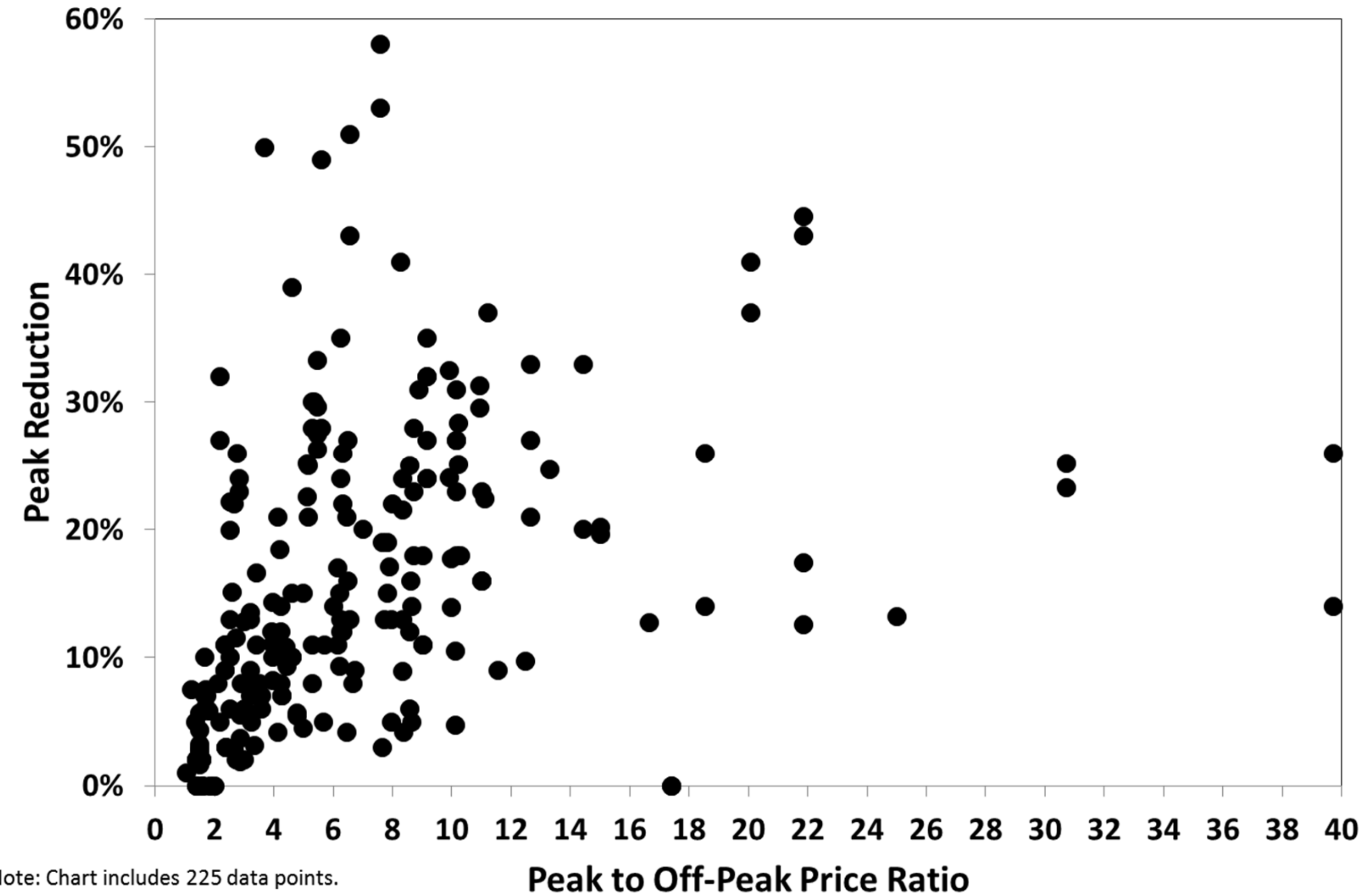
For residential customers, we rely on results from 225 pricing tests that have been conducted in a total of 42 pilots in the U.S. and internationally over roughly the past decade

Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California

Large C&I impacts are based on experience with full-scale programs in the Northeastern U.S.

To estimate residential impacts, we begin with a survey of impacts from recent pilots

Results of All Residential Time-Varying Pricing Tests



Note: Chart includes 225 data points.

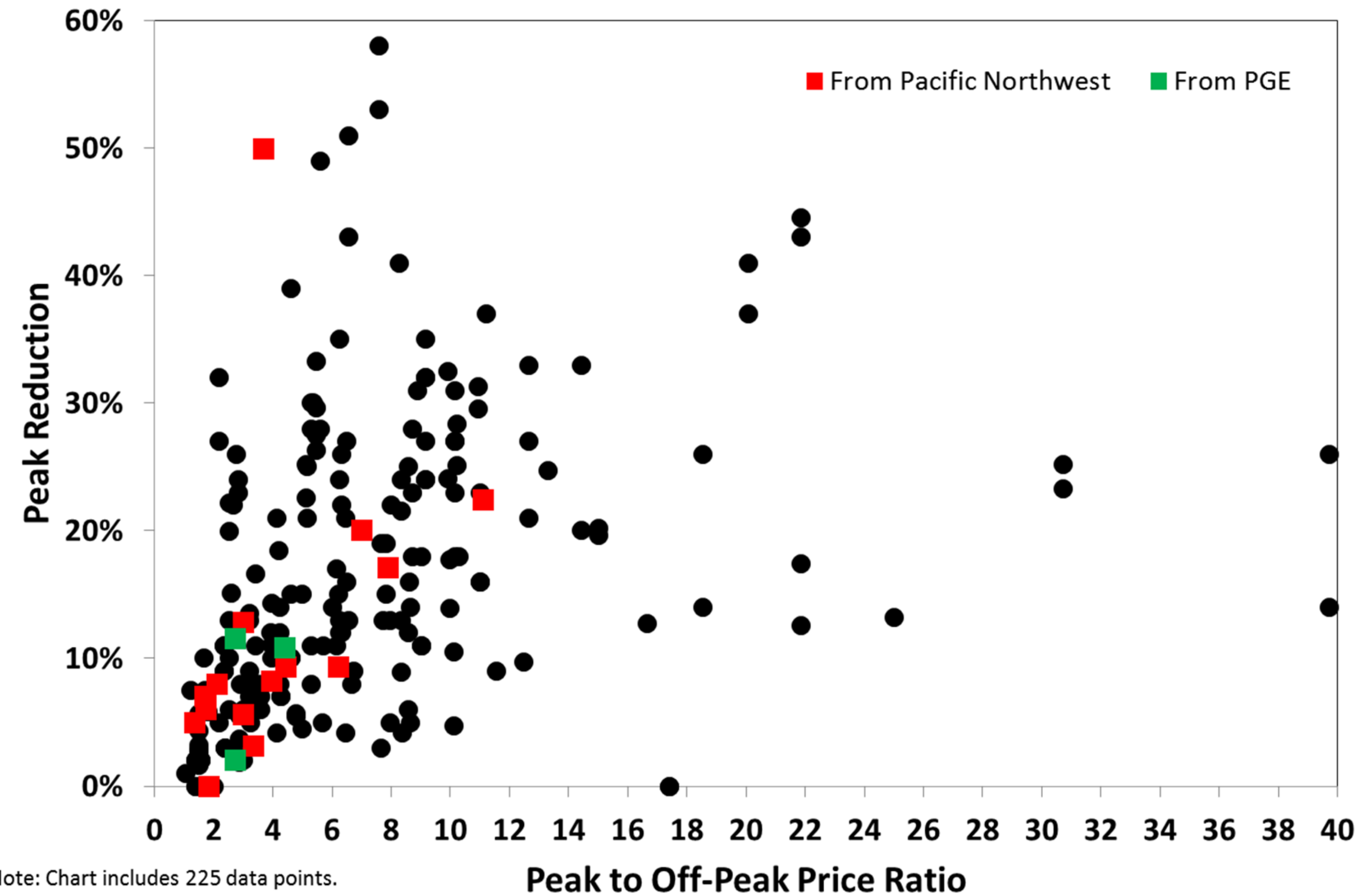
Our database of dynamic pricing pilots includes seven that have been conducted in the Pacific Northwest

Utility/Organization	State/Province	Name of Pilot	Year(s)	Rates Tested	Range of Price Ratios	Range of Peak Prices	Range of Impacts	Number of Pilot Participants	Season of System Peak
BC Hydro	British Columbia	Residential TOU/CPP Pilot	2007-2008	TOU CPP	TOU: 3.0-6.2 CPP: 7.9-11.1	TOU: 19-28¢ CPP: 50¢	TOU: 3-13%, CPP: 17-22%	TOU: 1,031 CPP: 273	Winter
Idaho Power	Idaho	Energy Watch (EW) and Time-of-Day (TOD) Pilot Programs	2005-2006	TOU CPP	TOU: 1.8 CPP: 3.7	TOU: 8¢ CPP: 20¢	TOU: 0% CPP: 50%	TOU: 85 CPP: 68	Summer
PacifiCorp	Oregon	TOU Rate Option	2002-2005	TOU	Summer: 1.7-2.1 Winter: 1.7	Summer: 11-14¢ Winter: 11¢	Summer: 6-8% Winter: 7%	~1200	Summer Winter
Portland General Electric (PGE)	Oregon	Residential TOU Option	2002-2003	TOU	2.7	8¢	8%	1,900	Winter
Portland General Electric (PGE)	Oregon	Critical Peak Pricing Pilot	2011-2013	CPP	4.4	44¢	11%	996	Winter
Puget Sound Energy	Washington	TOU Program	2001	TOU	1.4	See notes	5%	300,000	Winter
US DOE, PNNL, BPA, PacifiCorp, Portland General Electric, Public Utility District #1 of Clallam County, and City of Port Angeles	Washington/ Oregon	Olympic Peninsula Project	2006-2007	CPP	7.0	35¢	20%	112	Winter

Notes:
Could not find published estimates of TOU prices for Puget Sound Energy; only the price differential was available.
Price ratios are presented on an all-in basis.

The Pacific Northwest price ratios and impacts are generally consistent with those of other pilots

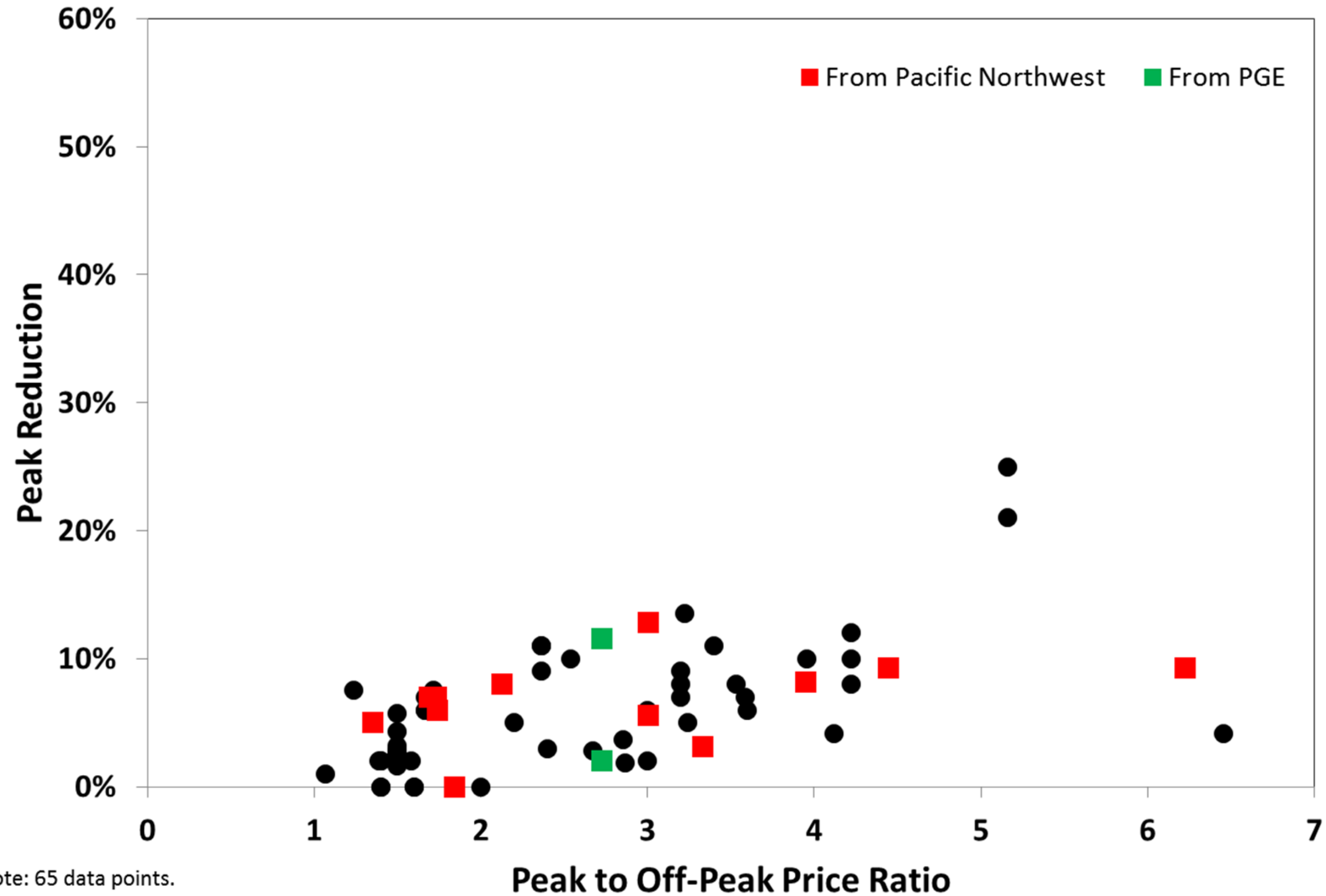
Results of All Residential Time-Varying Pricing Tests



Note: Chart includes 225 data points.

To estimate TOU impacts, we focus only on those pilots which tested TOU rates

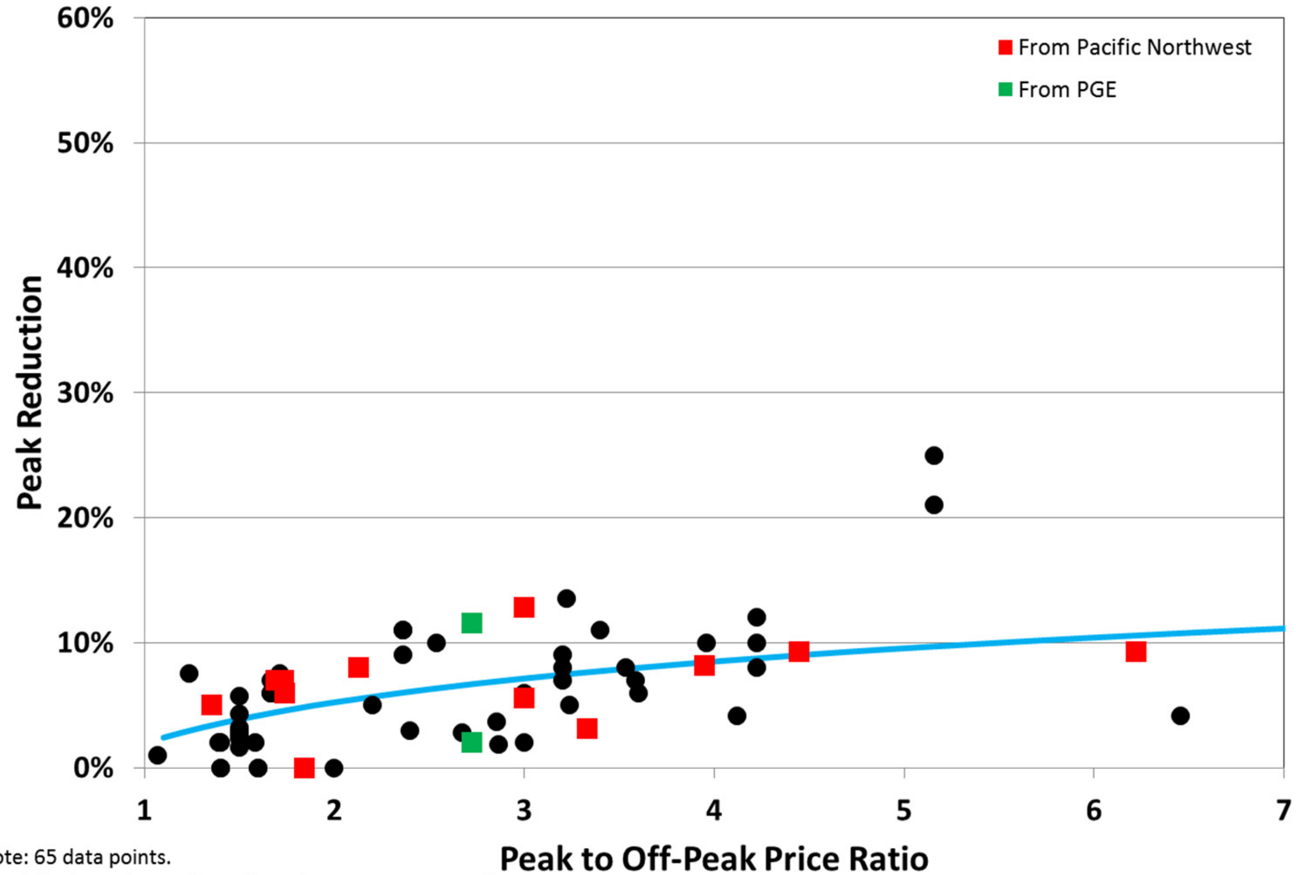
Results of Residential TOU Pricing Tests



Note: 65 data points.

We then fit a curve to the summer data to capture the relationship between price ratio and impacts

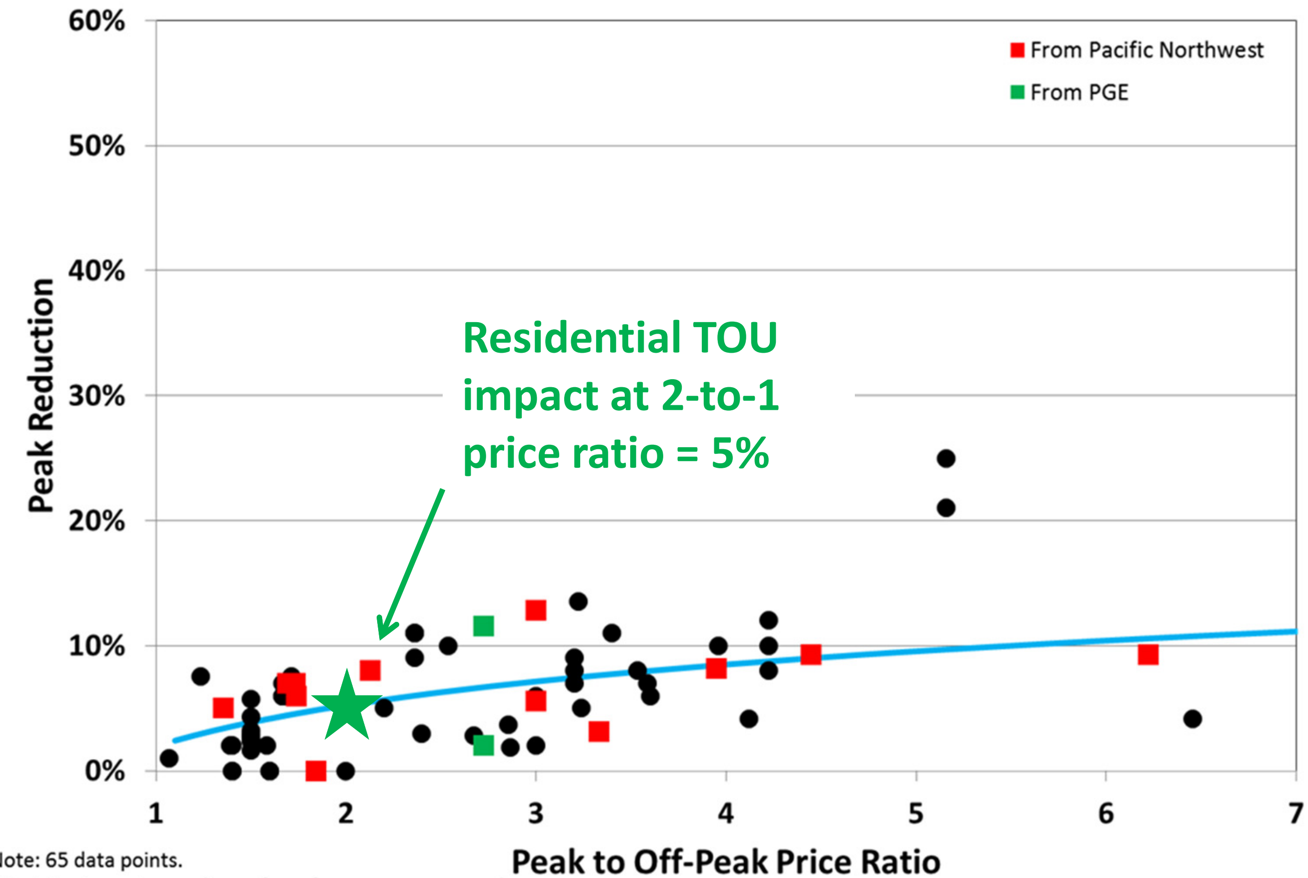
Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

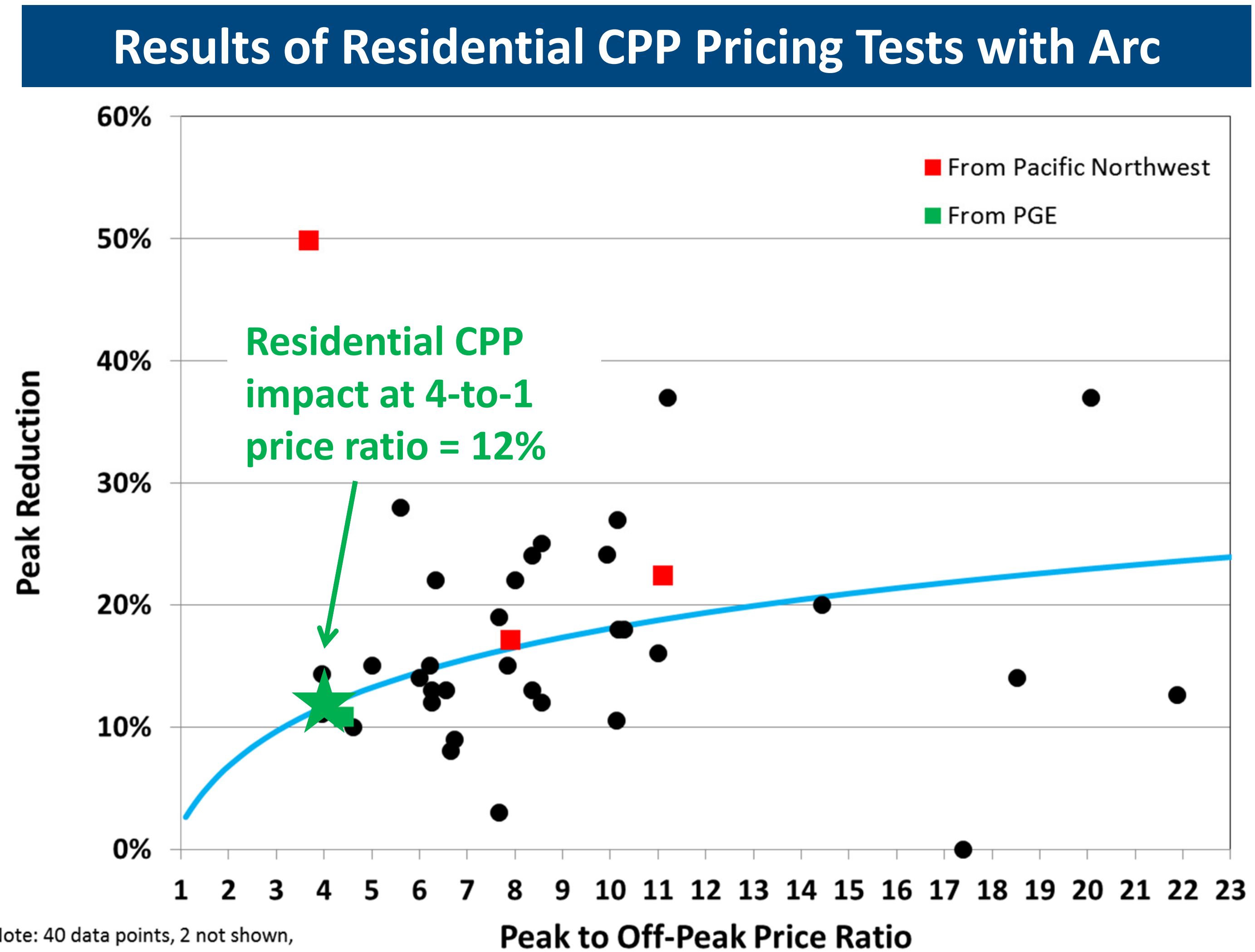
We use the arc to simulate the impact of the residential TOU rate for our study

Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

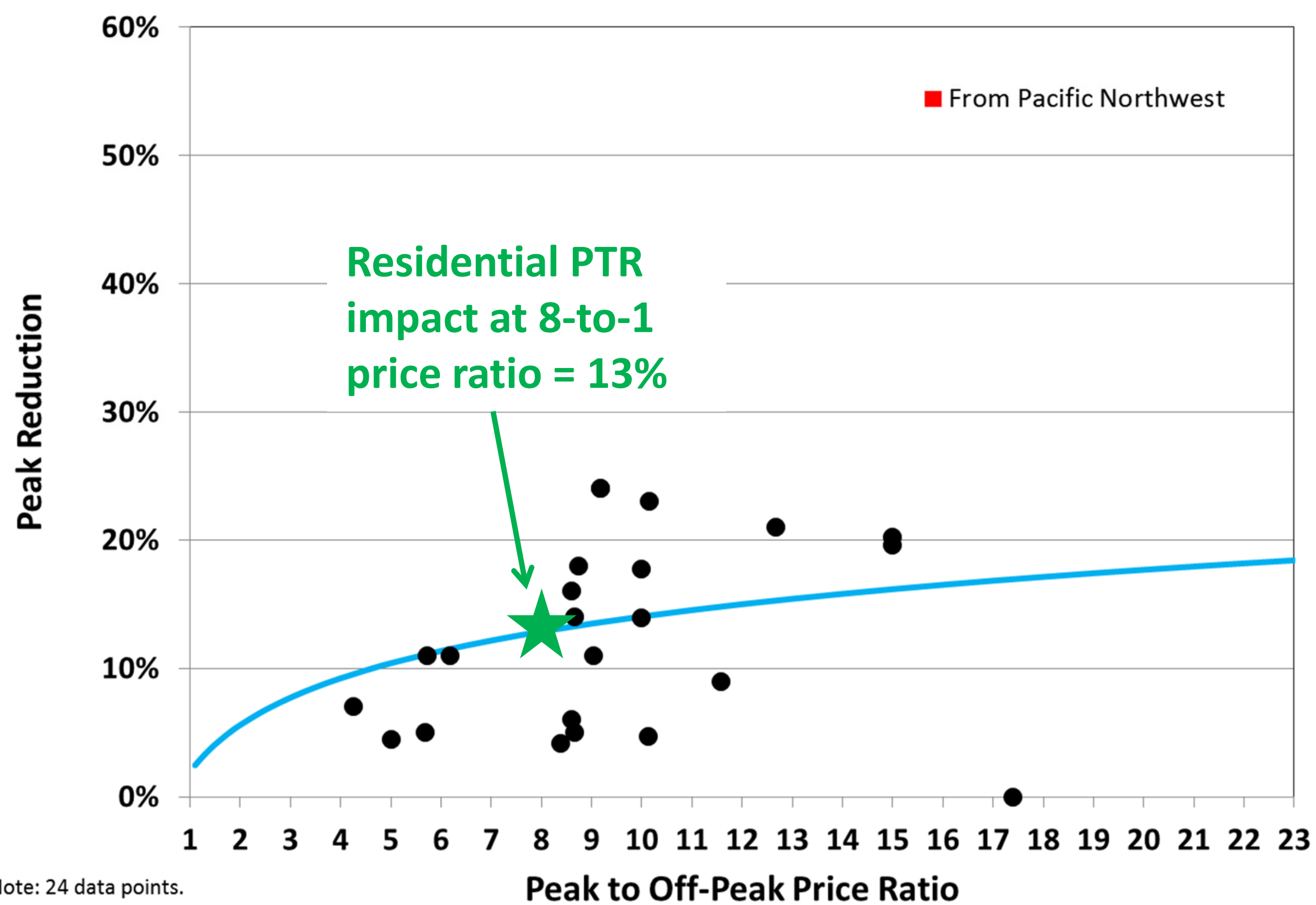
The same approach was used to estimate CPP impacts



Note: 40 data points, 2 not shown,
1 dropped as outlier in regression. 5 winter impacts are shown for reference purposes only.

PTR impacts were also estimated using the same approach

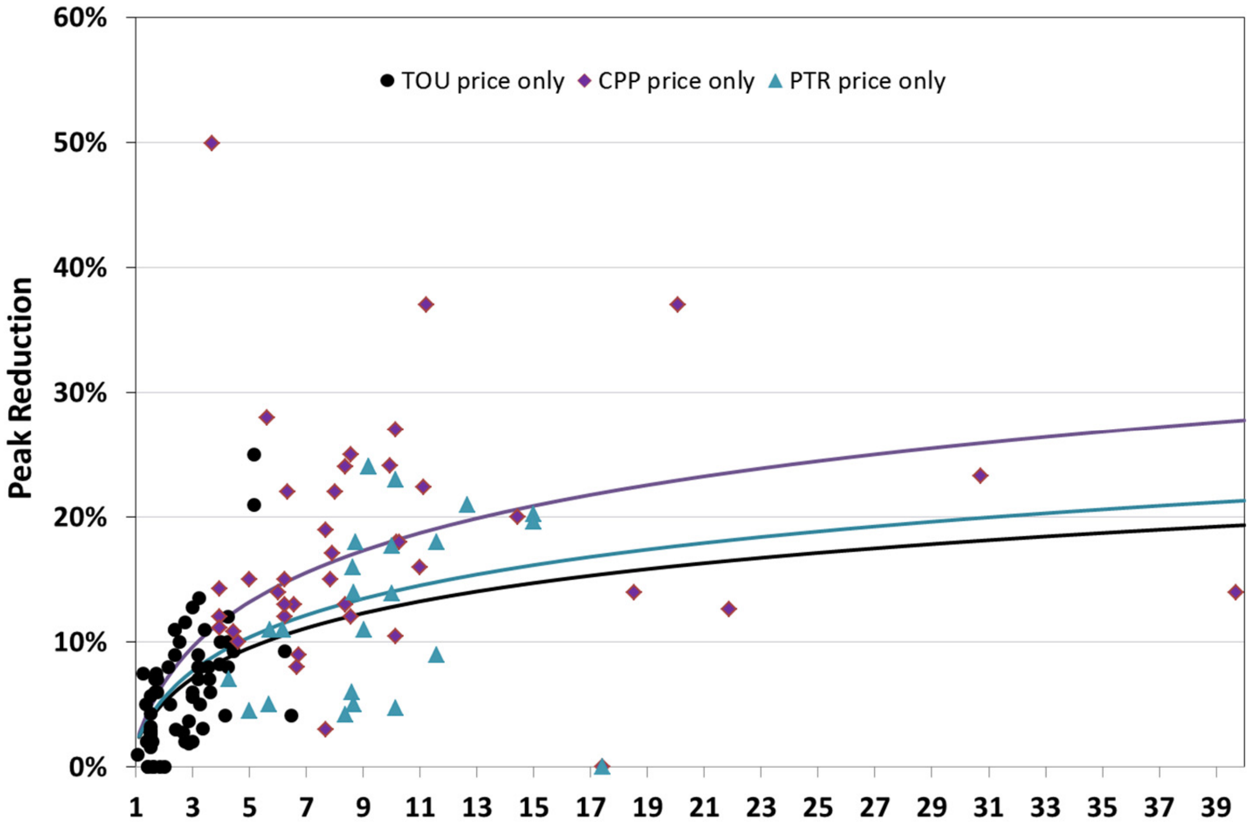
Results of Residential PTR Pricing Tests with Arc



Note: 24 data points.
2 winter impacts are shown for reference purposes only.

Price elasticity appears to be higher for CPP rates than PTR or TOU

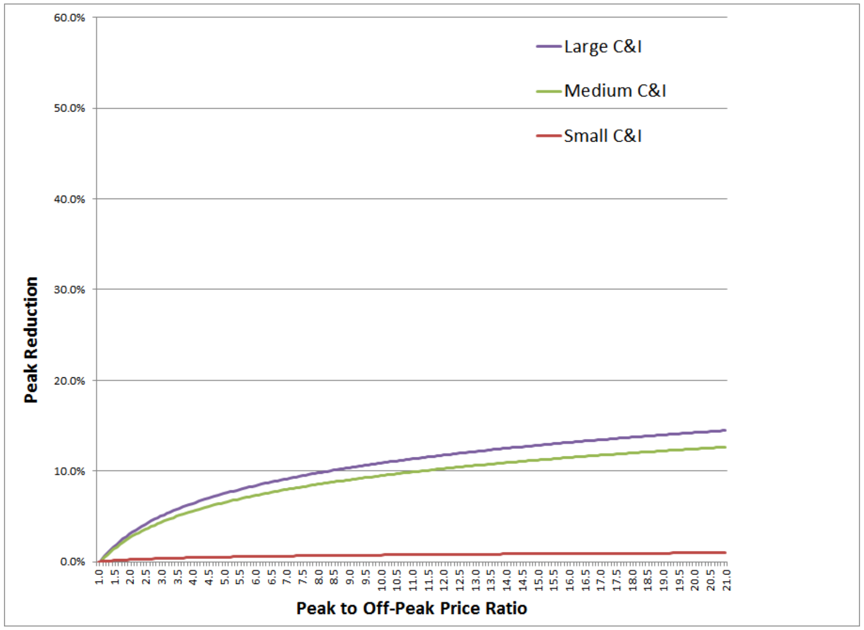
Results of All Residential Time-Varying Pricing Tests



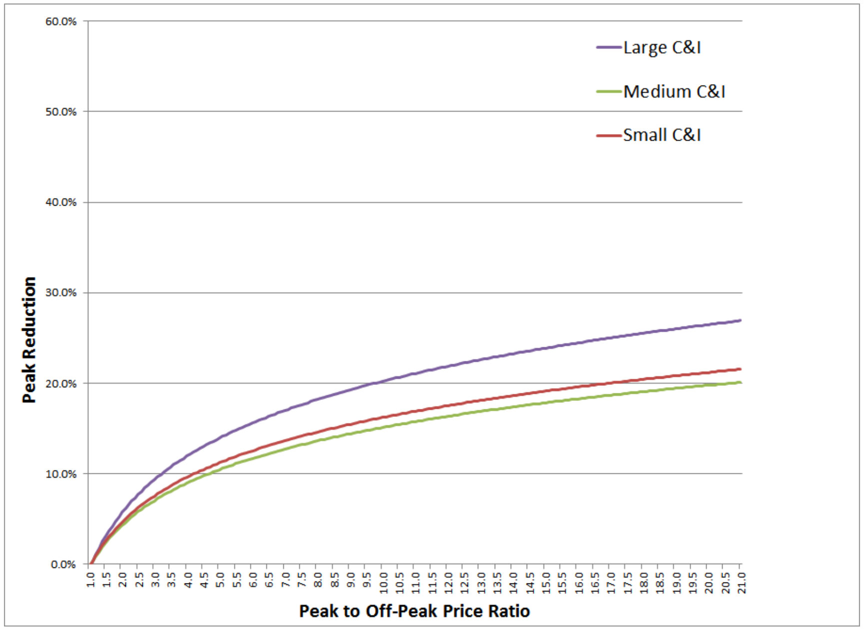
Note: 129 data points,
1 dropped as outlier in regression. 26 winter impacts are shown for reference purposes only.

C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers

C&I Arcs without Tech



C&I Arcs with Tech



Seasonal variation is based on the relationship observed in a limited number of pilots

To develop winter impact estimates, we created a scaling factor based on the relationship observed in pilots that tested both rates

The challenge is that there is not a consistent seasonal relationship across these pilots (see table)

Recognizing this uncertainty, but remaining consistent with the directional relationship in the PGE studies, we assumed a slightly higher degree of price responsiveness (10%) in the winter than in the summer

New primary research (e.g., the upcoming PTR pilot) is needed to refine this assumption

Pilot	Winter impact relative to summer
PGE TOU	Much larger (6x)
PGE CPP	Slightly larger*
PacifiCorp	Similar
Ontario TOU	Slightly smaller
Australian TOU	Much smaller (0.4x)
Xcel	Relationship varies

* Based on very limited summer data

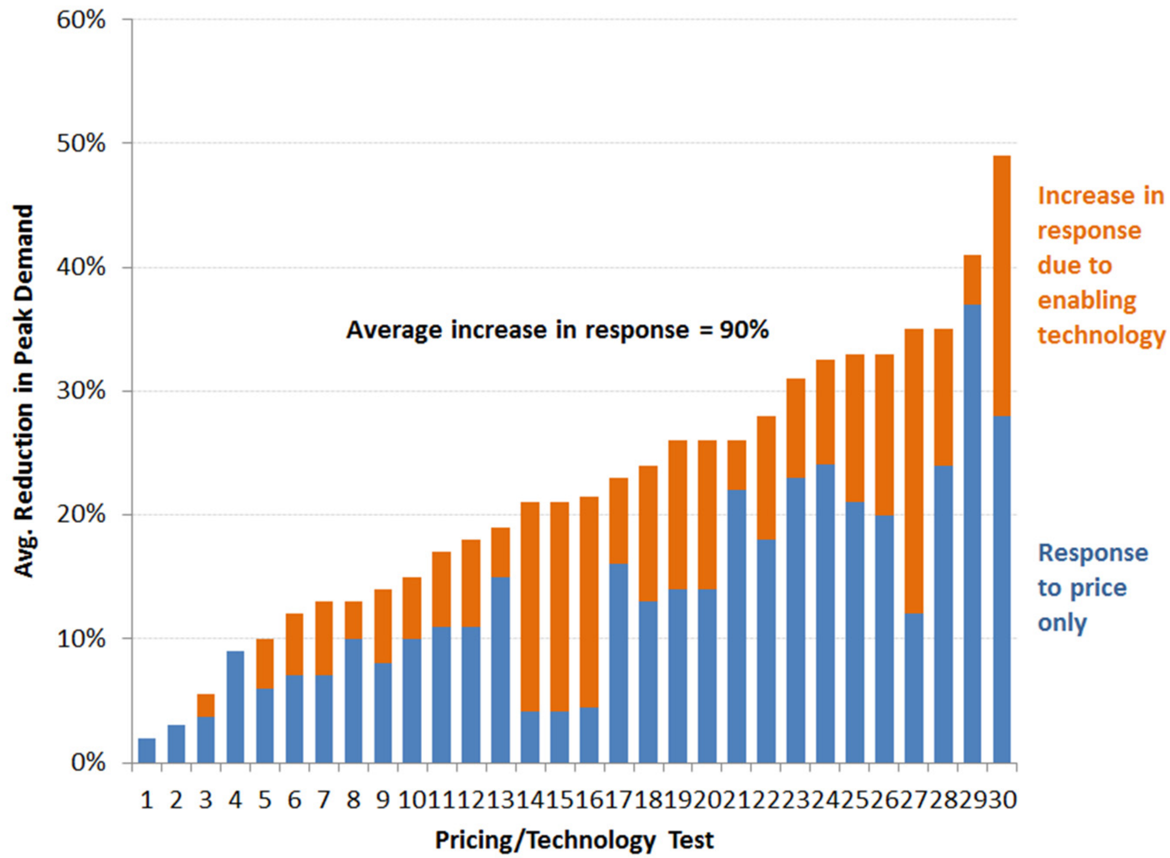
Impacts are scaled to account for enabling technology

Based on the relationship observed in other pilots, we assume a 90% increase in response attributable to technology (largely smart thermostats)

Winter technology impacts are assumed to be 80% of summer technology impacts based on the relationship observed in direct load control programs

TOU is not coupled with enabling technology because it does not have a dispatchable price signal

Price Response with and without Tech



Per-customer pricing impacts are scaled down in the opt-out deployment scenario

A new dynamic pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment

This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario; note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger

Per-customer TOU impacts were 40% lower when offered on an opt-out basis

Per-customer CPP impacts were roughly 50% lower

We have accounted for this relationship in our modeling of the residential impacts

We also simulated the impact of a TOU rate for irrigation customers

A 2001/2002 irrigation TOU pilot in Idaho found that customers produced, on average, a 9% reduction in peak for a TOU with a 3.5-to-1 price ratio

We used the Arc of Price Responsiveness to scale these impacts to the TOU price ratio we're analyzing in this study

The resulting peak reduction estimate is 4.7% for a TOU rate

Summary of draft results

		Without Tech			With Tech		
		TOU	CPP	PTR	TOU	CPP	PTR
Opt-in Deployment							
Residential	Summer	5.2%	11.7%	12.9%	N/A	31.0%	34.2%
	Winter	5.8%	12.8%	14.2%	N/A	24.8%	27.4%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A
Opt-out Deployment							
Residential	Summer	3.1%	5.8%	6.4%	N/A	15.5%	17.1%
	Winter	3.5%	6.4%	7.1%	N/A	12.4%	13.7%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A

Notes:

Impacts are average per eligible participant – individual participants could produce larger or smaller impacts

For ease of comparison, tech impacts are expressed as a % of the average customer even though they would only apply to customers with electric A/C or space heat, who have higher peak demand

Non-Pricing Programs Included in Prior PGE Studies

We estimate per-participant impacts for the following non-pricing programs from prior studies

	Residential	Small C&I	Medium C&I	Large C&I
DLC - A/C	X	X		
DLC - Space heat	X	X		
DLC - Water heating	X	X		
DLC - Auto-DR			X	X
Curtailable tariff			X	X

Updates to assumptions for conventional non-pricing programs were fairly minor

Impact assumptions remain stable for the conventional non-pricing programs analyzed in prior studies for PGE, since these programs are well established with a long history of performance

Where applicable, we revised the estimates to be more consistent with findings of studies in the Pacific Northwest

We also compared the 2012 assumptions to those of the more recent PacifiCorp potential study and resolved any discrepancies to ensure consistency

We relied on the following Pacific Northwest DR studies to refine our impact estimates

- Avista, "Idaho Load Management Pilot," 2010
- Cadmus Group, "Kootenai DR Pilot Evaluation: Full Pilot Results," 2011
- Cadmus Group, "OPALCO DR Pilot Evaluation", 2013
- Itron, "Draft Phase I Report Portland General Electric Energy Partner Program Evaluation," 2015
- Lawrence Berkeley National Lab, "Northwest Open Automated Demand Response Technology Demonstration Project," 2009
- Michaels Energy, "Demand Response and Snapback Impact Study", 2013
- Navigant and EMI, "2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program," 2012
- Navigant, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", 2014
- Nexant, "SmartPricing Options Final Evaluation - The Final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study", 2014
- Rocky Mountain Power, "Utah Energy Efficiency and Peak Reduction annual Report", 2014

The following assumptions were updated for this study

Residential air-conditioning DLC

- Reduced slightly from 1.0 kW to 0.8 kW to reflect lower-than-average impacts observed in Pacific Northwest studies

Residential space heat DLC

- Increased from 0.6 kW to 1.0 kW
- Even higher impacts are observed in Pacific Northwest studies, but a 2004 PGE study found impacts in the 0.7 kW range
- Note that the relationship between space heat and air-conditioning has been reversed based on this revision

Assumption updates (cont'd)

Small C&I air-conditioning and space heat

- Scaled to be consistent with residential assumption (1.5x residential load reduction capability)

Medium and Large C&I Auto-DR

- Increased from 15-20% of peak load to 30% of peak load to establish appropriate relationship between curtailable tariff impacts and Auto-DR impacts
- Assumed to be offered in conjunction with curtailable tariff type of program and provides 50% incremental increase in load reduction relative to impact with no technology
- There is a significant range of uncertainty around this assumption; to be discussed further with PGE relative to the findings of its Auto-DR pilot, which referenced a fairly broad range of impacts

Summary of assumptions for non-pricing impacts from prior studies

Class	Program	Season	2012 Assumption	Updated 2015 Assumption
Residential	DLC - Central A/C	Summer	1.0 kW	0.8 kW
Residential	DLC - Space Heat	Winter	0.6 kW	1.0 kW
Residential	DLC - Water Heating	Summer	0.4 kW	0.4 kW
Residential	DLC - Water Heating	Winter	0.8 kW	0.8 kW
Small C&I	DLC - Central A/C	Summer	2.0 kW	1.2 kW
Small C&I	DLC - Space Heat	Winter	1.2 kW	1.5 kW
Small C&I	DLC - Water Heating	Summer	1.2 kW	1.2 kW
Small C&I	DLC - Water Heating	Winter	0.6 kW	0.6 kW
Medium C&I	DLC - Auto-DR	Year-round	15%	30%
Medium C&I	Curtailable tariff	Year-round	N/A	20%
Large C&I	DLC - Auto-DR	Year-round	20%	30%
Large C&I	Curtailable tariff	Year-round	20%	20%

New Non-Pricing Programs Not Included in Prior PGE Studies

We estimated per-participant peak demand impacts for three new programs; two more are in development

Draft impact estimates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Impact estimates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- Developing assumptions for these programs requires ongoing interaction with PGE staff, which is already underway

We relied on the following data sources to develop our impact estimates for new non-pricing programs

- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015
- Austin Energy, PowerSaver Program website, Accessed May 1, 2015
- Con Ed of NY, Rider L – Direct Load Control Program filing, Case C14-E-0121, April 3, 2014
- Edison Foundation, Innovations Across the Grid, December 2013 and December 2014
- Hydro One website, Accessed May 1, 2015.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Nest Inc., White Paper: Rush Hour Rewards, Results from Summer 2013, May 2014.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- Rocky Mountain Power, Utah Energy Efficiency and Peak Reduction Annual Report, June 26, 2013 and May 16, 2014.
- S. Blumsack and P. Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013", March 5, 2015.
- Southern California Edison website, Accessed May 1, 2015.

We have identified key elements of "Bring Your Own Device" Type Programs

Bring Your Own Device/Thermostat ("BYOD" or "BYOT") programs provide an alternative to utility direct-install programs, reducing equipment and installation costs

The incentive structure for participating in BYOD programs is diverse

- One-time rebate/refund, with or without a minimum time commitment
- Fixed annual/monthly participation incentive in addition to a one-time rebate
- Variable monthly incentive based on kWh savings

Programs also include monetary incentives to thermostat vendors and annual compensation for portal/interface maintenance

Customers can opt out of individual events without penalty

Our assumptions are based on research of five different BYOD programs

We have identified five primary programs

- Hydro One
- Austin Energy
- Con Edison of NY
- Southern California Edison
- "Rush Hour Rewards (RHR)" program by Nest Inc.

These programs have been able to successfully sign up new customers

- As of December 2014, Austin Energy had enrolled 7,000 thermostats (out of ~383,000 residential customers), with a planned expansion to 70,000 thermostats
- Con Edison enrolled 2,000 customers in its first year and believes that it can achieve 5,000 new sign-ups each year
  - Low enrollment may be explained by a relatively small number of eligible thermostats currently installed (~30,000)
- In 2013 Nest's Rush Hour Rewards program included over 2,000 customers from Austin Energy, Reliant, and Southern California Edison. Nest is currently expanding this program, and enrollment has likely increased since then

Our BYOD program impact estimates are similar to those of other Residential A/C DLC programs

Austin Energy's *Power Partner Thermostat* program has achieved a per device load shed of up to 33% during a peak event

Con Edison expects 1.0 kW of peak load reduction per thermostat based on its experience with other Residential DLC participants

Nest's "RHR" program studied the peak load impacts across three different utilities (Austin Energy, Reliant, and Southern California Edison)

- A total of 19 events were studied across the three utilities
- Each event reduced load by an average of 1.18 kW per device
- Only 14.5% of customers reduced their temperature during an event

Research suggests a per-customer peak reduction of around 1 kW

Utility/Program	Number of Participants	Customer Incentive	Peak Demand Impact (%/customer)	Peak Demand Impact (kW/customer)
Austin Energy	7,000	$85/one-time	33%	N/A
SCE	N/A	$1.25/kWh reduced	N/A	N/A
Con Ed of NY	2,000	$85/one-time; $25 annual for additional participation	N/A	1.0
Hydro One	2,000	$100-125/one-time	N/A	N/A
Nest Inc.'s "RHR"	2,000	N/A	55%	1.18

The available data suggests that per-customer impacts are similar to that of a utility-administered DLC program; we therefore assume the same summer and winter impacts that are being modeled in the conventional programs

Impacts of Behavioral DR programs were based primarily on programs conducted by OPower

Behavioral Demand Response aims to increase customer engagement

Achieved via a software-centered approach based on targeted and customized email, mobile, and interactive voice response (IVR) communications

Customers are notified of DR events ahead of time and receive post-event feedback on performance

Easy to deploy and scale relative to other DR programs that require hardware installations

No financial incentives are offered for load reductions

OPower reports significant summer peak savings from BDR programs

Deployed to 150k customers in Consumers Energy (MI), Green Mountain Power (VT), and Glendale Water & Power (CA)

- Achieved peak load reductions of 3% on average (max 5%)

BGE launched BDR in combination with a Peak Time Rebate Program

- 5% average reduction at peak across homes without a device (~0.2kW/home)

Added benefit of customer engagement and increased satisfaction, although it is possible that customers could find the notifications to be intrusive

Others are also exploring the potential of Behavioral DR

In Minnesota, four electric co-ops used MyMeter – a program that gives utility customers more detailed info about their energy use

- In 2013, demand reduction ranged between 1.8 – 2.8% per customer
- This program is different from those offered by Opower, as information is driven through an in-home display

In the fall of 2012 and summer of 2013, Green Mountain Power study tested a behavioral DR-like program

- GMP ran fourteen peak event tests for seven treatment groups with varying rate structures and informational treatments
- Customers who stayed on a flat rate, but were notified of peak events, reduced by peak demand by 3.4% and 8.2% in 2012 and 2013, respectively (0.030 - 0.073 kW)

We have heard that Silver Spring Networks may be developing BDR capability. However, we have not yet found any evidence and further research is needed

Research suggests a 3% reduction impact for Behavioral DR programs would be reasonable

Utility/Program	Summer Peak Demand Impact (%)
Consumers Energy, Green Mountain Power, and Glendale Water & Power	3.0%
BGE	5.0%
MN electric co-ops (MyMeter Program)	1.8-2.8%
Green Mountain Power	3.4-8.2%

- Since little is known about the persistence of BDR impacts over the long-term, we assume an impact from the lower end of this range, of 3%
- To establish a winter impact, we use the same assumption that is used in our dynamic pricing analysis, that winter impacts are 10% higher than summer impacts; this is because BDR similarly relies on behavioral response from customers rather than targeting a specific end-use

There is support for high per-customer impacts from Irrigation Load Control programs

Irrigation Load Control consists of scheduling or shutting off irrigation pumps above a certain size

The programs researched are available only during the summer and typically provide a fixed (per event) incentive payment

Customers can opt out of a maximum number of events per year

In the Pacific Northwest, PacifiCorp has experience with such programs in Idaho and Utah; Idaho Power and a number of electric cooperatives also offer irrigation load control programs

Southern California Edison and Entergy also offer irrigation load control programs, as do coops in other parts of the US

Estimates of irrigation peak load reductions are fairly large on a per-participant basis

Rocky Mountain Power (part of PacifiCorp) ran its irrigation load control program in 2009 and 2010 with customers in Idaho

- About 2,000 customers were enrolled between 2009 and 2010
- Aggregate reductions in 2009 was 206 MW out of 260 MW of irrigation load
- In 2010, reductions amounted to 156 MW out of 283 MW of load

RMP also ran a program in Utah that achieved reductions in the 62-73% range

FERC's DR Study reports peak demand reductions of about 60% for electric cooperatives

Southern California Edison and Entergy report impacts of 82% and 49%, respectively

In its 2014 DR potential study, PacifiCorp's assumed that 100% of agricultural irrigation load could be curtailed during an event

Our research suggests peak reductions in the 65%-75% range for Irrigation Load Control programs

Utility/Program	Peak Demand Impact (MW)	Baseline Demand (MW)	Peak Demand Impact (%)
PacifiCorp DR potential study	N/A	N/A	100%
Southern California Edison			89%
RMP 2009	205	260	79%
RMP 2010	156	283	55%
RMP 2012	35	48	73%
RMP 2013	16	26	62%
Various Coops (FERC 2013 Study)	N/A	N/A	60% (mean)
Entergy (Arkansas)			49%

Notes: Peak demand impact % calculated for RMP 2009-2012 as (peak demand impact) / (baseline demand).
RMP 2009-10 from The Cadmus Group, *Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program,* March 24, 2011, pp. 1-2.
RMP 2012 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* Revised June 26, 2013, p. 19.
RMP 2013 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* May 16, 2014, p. 19.

Summary of Impact Assumptions for New Non-Pricing programs

Program	Winter Peak Demand Impact (kW)	Winter Peak Demand Impact (%)	Summer Peak Demand Impact (kW)	Summer Peak Demand Impact (%)
BYOD	1.0 kW		0.8 kW	
Behavioral DR		3.3%		3%
Irrigation Load Control		N/A		70%

Appendix C:
Cost-Effectiveness Adjustments

Should the incentive payment be included as a cost in the TRC cost-effectiveness test?

If every participant valued their loss of comfort at an amount equal to the incentive payment (assume $90/year), then it would be correct to include the full incentive amount as a cost in the TRC test

However, every participant is unique and will therefore value the loss of comfort differently; consider four prototypical customers in a DLC program:

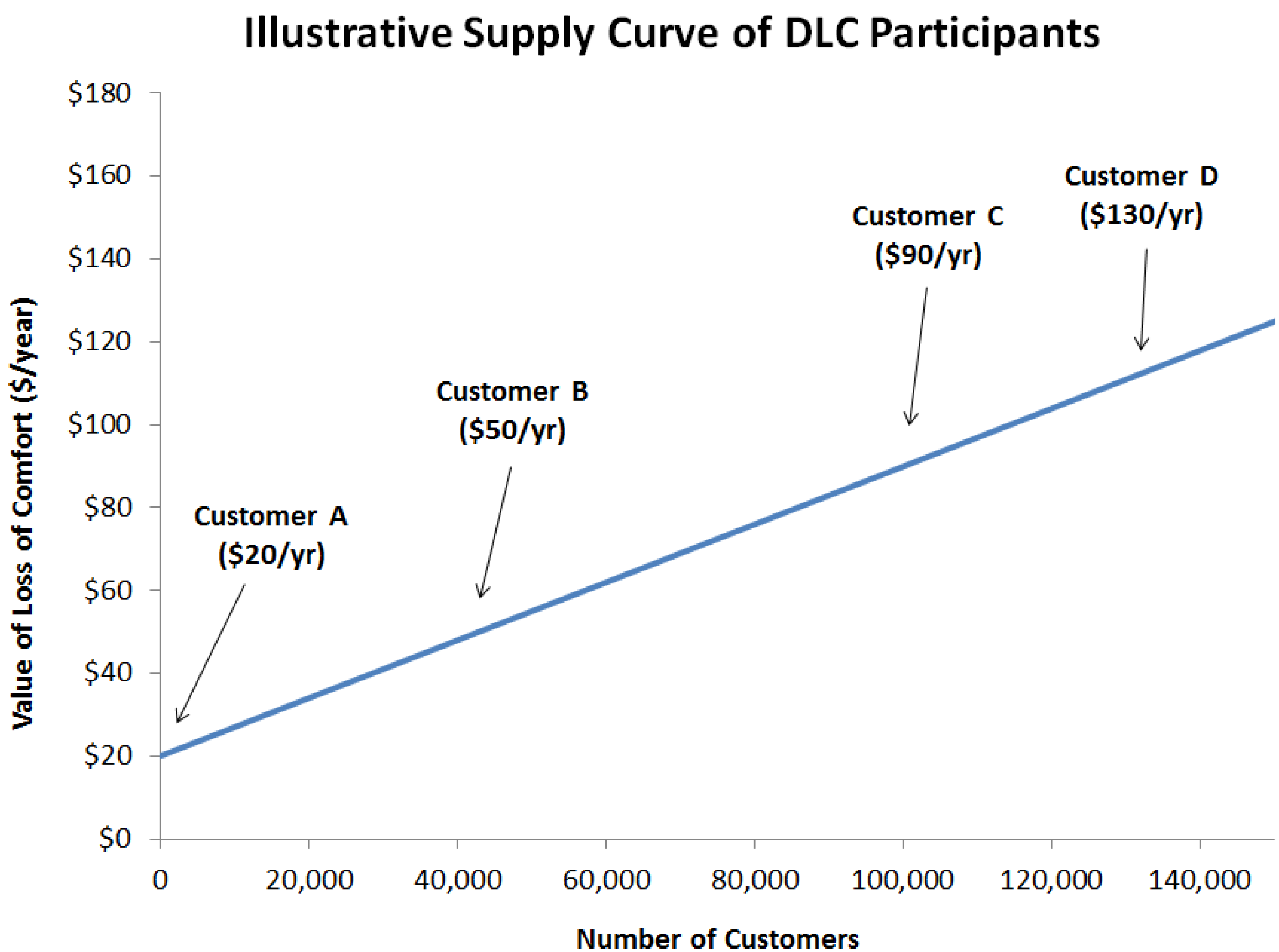
Customer A, for example, is rarely home and therefore only values his loss of comfort from participating in the DLC program at $20/year – his "profit" from participating in the program would be $70/year

Customer B is home more often, but does not particularly mind relinquishing control of his air-conditioner occasionally; he values the loss of comfort at $50/kW year

Customer C places higher value on comfort, and the cost of participating is roughly the same to him as the incentive payment that he receives; this is the "marginal" customer

Customer D is more temperature-sensitive and does not like the idea of curtailing use of his air-conditioner; his value of lost comfort is $130/year, or $40 more than the incentive payment that is being offered

The prototypical customers represent a “supply curve” of participants in the DLC program



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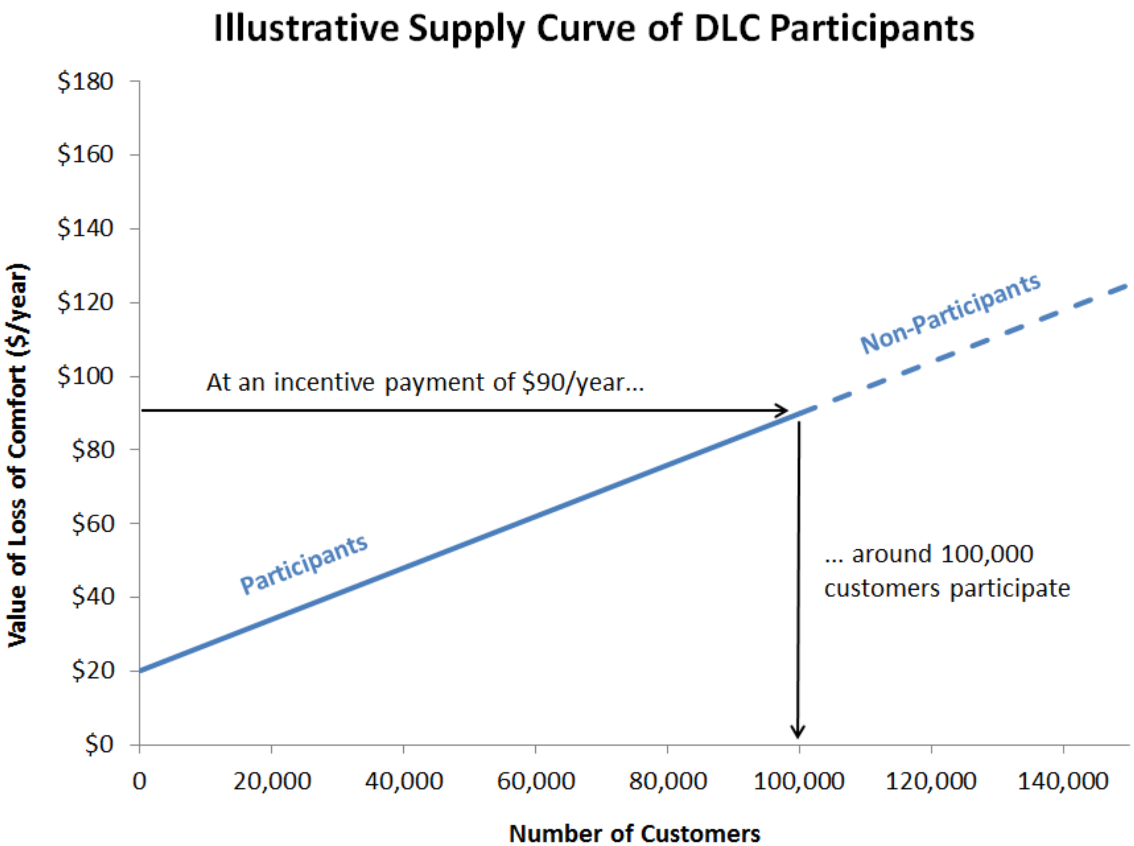
The cost associated with "loss of comfort" should be the average across all participants



- Customers will only participate if their loss of comfort is less than the incentive payment
- In this purely illustrative example, the average loss of comfort among participants is $50 per year, which is 55% of the incentive payment
- The remaining 45% is simply a transfer payment and should not be considered a cost in the TRC test (which is consistent with treatment of energy efficiency programs)
- While that estimate would change depending on the slope of the supply curve, it is more realistic than assuming all customers incur a cost of $90/year
- We count 50% of the incentive as a cost in the base case of our analysis for this reason

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We tested the sensitivity of our findings to the amount of incentive counted as a cost

Class	Program	Opt-in: Base Case (50%)	Opt-in: 0%	Opt-in: 100%
Residential	AC DLC	1.12	1.57	0.87
Residential	Space Heating DLC	1.31	1.78	1.03
Residential	Water Heating DLC	1.30	2.09	0.94
Residential	AC/Space Heating DLC	1.82	3.10	1.29
Residential	TOU	1.24	1.24	1.24
Residential	PTR	1.75	4.49	1.24
Residential	PTR w/Tech	1.32	2.26	0.98
Residential	CPP	1.62	1.62	1.62
Residential	CPP w/Tech	1.49	1.49	1.49
Residential	Behavioral DR	0.85	0.80	0.80
Residential	BYOT - AC	1.94	3.55	1.27
Residential	BYOT - Space Heating	1.98	3.30	1.41
Residential	BYOT - AC/Space Heating	2.43	5.39	1.57
Small C&I	AC DLC	1.00	1.51	0.75
Small C&I	Space Heating DLC	1.07	1.52	0.83
Small C&I	Water Heating DLC	0.79	1.14	0.60
Small C&I	AC/Space Heating DLC	1.40	2.41	0.98
Small C&I	TOU	0.06	0.06	0.06
Small C&I	PTR	0.17	0.18	0.16
Small C&I	PTR w/Tech	0.79	1.03	0.64
Small C&I	CPP	0.08	0.08	0.08
Small C&I	CPP w/Tech	0.55	0.55	0.55
Medium C&I	Third-Party DLC	1.59	2.09	1.23
Medium C&I	Curtailable Tariff	5.37	28.26	2.96
Medium C&I	CPP	1.94	1.94	1.94
Medium C&I	CPP w/Tech	1.38	1.38	1.38
Large C&I	Third-Party DLC	1.57	2.06	1.22
Large C&I	Curtailable Tariff	6.30	168.36	3.21
Large C&I	CPP	14.42	14.42	14.42
Large C&I	CPP w/Tech	6.70	6.70	6.70
Agricultural	Pumping Load Control	0.78	1.02	0.63
Agricultural	TOU	0.29	0.29	0.29

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The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-in** program deployment

Cost-effectiveness sensitivity case results (cont'd)

Class	Program	Opt-out: Base Case (50%)	Opt-out: 0%	Opt-out: 100%
Residential	AC DLC	N/A	N/A	N/A
Residential	Space Heating DLC	N/A	N/A	N/A
Residential	Water Heating DLC	N/A	N/A	N/A
Residential	AC/Space Heating DLC	N/A	N/A	N/A
Residential	TOU	1.24	1.05	1.05
Residential	PTR	1.49	2.76	1.06
Residential	PTR w/Tech	0.86	1.16	0.69
Residential	CPP	1.15	1.04	1.04
Residential	CPP w/Tech	0.83	0.80	0.80
Residential	Behavioral DR	1.04	0.97	0.97
Residential	BYOT - AC	N/A	N/A	N/A
Residential	BYOT - Space Heating	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	N/A	N/A	N/A
Small C&I	AC DLC	N/A	N/A	N/A
Small C&I	Space Heating DLC	N/A	N/A	N/A
Small C&I	Water Heating DLC	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	N/A	N/A	N/A
Small C&I	TOU	0.11	0.09	0.09
Small C&I	PTR	0.30	0.30	0.26
Small C&I	PTR w/Tech	0.82	1.07	0.66
Small C&I	CPP	0.11	0.10	0.10
Small C&I	CPP w/Tech	0.60	0.58	0.58
Medium C&I	Third-Party DLC	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	N/A	N/A	N/A
Medium C&I	CPP	4.80	3.56	3.56
Medium C&I	CPP w/Tech	1.76	1.63	1.63
Large C&I	Third-Party DLC	N/A	N/A	N/A
Large C&I	Curtailable Tariff	N/A	N/A	N/A
Large C&I	CPP	42.10	34.79	34.79
Large C&I	CPP w/Tech	7.15	7.02	7.02
Agricultural	Pumping Load Control	N/A	N/A	N/A
Agricultural	TOU	0.83	0.63	0.63

The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-out** program deployment

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Avoided costs derates are derived from the California cost-effectiveness protocols

The California PUC currently defines three factors that are used to adjust avoided capacity costs to better reflect the value of demand response:

(A) **Availability:** "The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted."

(B) **Notification time:** "The B factor calculation should be done by examination of past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls… By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program."

(C) **Trigger:** "The C factor should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions.

Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE

For more information, see the 2010 California DR Cost Effectiveness Protocols report:
http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC

The CPUC is currently examining the possible modification and expansion of these factors

Avoided cost derates used in the PGE analysis

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

- Values at left represent the percent of the avoided cost that is attributed to the DR program
- Estimates are based on a survey of values developed by the California IOUs across a wide variety of DR programs
- Values are calibrated to capture appropriate relative relationships across the programs evaluated for PGE and intuitive estimates were developed for those programs for which there is not a clear example in the California data

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Appendix D:

Annual Potential Estimates and Benefit-Cost Ratios

See the accompanying MS Excel file titled “PGE DR Potential Results - Annual Tables.xlsx”.

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)
Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0	42.0	43.2	44.6	45.7
Residential	PTR	Summer	0.0	94.3	97.2	100.3	102.9
Residential	PTR w/Tech	Summer	0.0	23.5	24.3	25.0	25.7
Residential	CPP	Summer	0.0	76.2	78.3	80.8	82.9
Residential	CPP w/Tech	Summer	0.0	20.4	21.0	21.6	22.2
Residential	Behavioral DR	Summer	45.2	38.1	39.3	40.6	41.7
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0	0.5	0.6	0.6	0.6
Small C&I	PTR	Summer	0.0	1.7	1.8	2.0	2.1
Small C&I	PTR w/Tech	Summer	0.0	3.7	4.0	4.3	4.6
Small C&I	CPP	Summer	0.0	0.9	1.0	1.0	1.1
Small C&I	CPP w/Tech	Summer	0.0	2.2	2.3	2.5	2.6
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0	21.9	23.3	25.2	26.8
Medium C&I	CPP w/Tech	Summer	0.0	38.5	41.1	44.4	47.3
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0	40.9	44.3	48.4	52.1
Large C&I	CPP w/Tech	Summer	0.0	83.9	90.9	99.4	106.9
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0	1.7	1.6	1.4	1.3

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	11.0	106.5	120.9	134.2	144.3
Residential	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Residential	Water Heating DLC	Summer	3.6	31.0	32.3	33.8	35.2
Residential	AC/Space Heating DLC	Summer	1.4	12.3	13.0	13.7	14.3
Residential	TOU	Summer	0.0	22.7	23.9	24.6	25.3
Residential	PTR	Summer	0.0	42.6	44.7	46.1	47.3
Residential	PTR w/Tech	Summer	0.0	12.9	13.5	13.9	14.3
Residential	CPP	Summer	0.0	31.9	33.5	34.6	35.5
Residential	CPP w/Tech	Summer	0.0	9.6	10.1	10.4	10.7
Residential	Behavioral DR	Summer	1.1	9.5	9.8	10.2	10.4
Residential	BYOT - AC	Summer	1.9	42.1	44.5	46.9	49.0
Residential	BYOT - Space Heating	Summer	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - AC/Space Heating	Summer	0.9	7.7	8.1	8.6	8.9
Residential	Smart Water Heater DLC	Summer	0.1	7.6	20.5	33.7	44.5
Residential	Electric Vehicle DLC	Summer	0.4	1.3	2.7	4.9	6.9
Small C&I	AC DLC	Summer	1.5	12.8	13.8	14.9	15.9
Small C&I	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Small C&I	Water Heating DLC	Summer	0.1	0.7	0.7	0.8	0.8
Small C&I	AC/Space Heating DLC	Summer	0.4	3.4	3.7	4.0	4.2
Small C&I	TOU	Summer	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Summer	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Summer	0.0	1.2	1.4	1.5	1.6
Small C&I	CPP	Summer	0.0	0.2	0.3	0.3	0.3
Small C&I	CPP w/Tech	Summer	0.0	0.6	0.7	0.7	0.8
Medium C&I	Third-Party DLC	Summer	5.2	46.1	49.6	53.6	57.1
Medium C&I	Curtailable Tariff	Summer	23.3	24.6	26.5	28.6	30.4
Medium C&I	CPP	Summer	0.0	6.1	6.7	7.2	7.7
Medium C&I	CPP w/Tech	Summer	0.0	10.9	11.9	12.9	13.7
Large C&I	Third-Party DLC	Summer	7.0	62.8	68.6	75.1	80.7
Large C&I	Curtailable Tariff	Summer	75.5	80.4	87.8	96.1	103.3
Large C&I	CPP	Summer	0.0	11.4	12.6	13.8	14.9
Large C&I	CPP w/Tech	Summer	0.0	29.6	32.9	36.0	38.7
Agricultural	Pumping Load Control	Summer	0.5	3.8	3.5	3.2	2.9
Agricultural	TOU	Summer	0.0	0.3	0.3	0.2	0.2

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0%	1.2%	1.1%	1.1%	1.1%
Residential	PTR	Summer	0.0%	2.6%	2.6%	2.5%	2.5%
Residential	PTR w/Tech	Summer	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Summer	0.0%	2.1%	2.1%	2.0%	2.0%
Residential	CPP w/Tech	Summer	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Summer	1.3%	1.1%	1.0%	1.0%	1.0%
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP w/Tech	Summer	0.0%	1.1%	1.1%	1.1%	1.1%
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0%	1.1%	1.2%	1.2%	1.2%
Large C&I	CPP w/Tech	Summer	0.0%	2.3%	2.4%	2.5%	2.5%
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	0.3%	3.0%	3.2%	3.3%	3.4%
Residential	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Water Heating DLC	Summer	0.1%	0.9%	0.9%	0.8%	0.8%
Residential	AC/Space Heating DLC	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	TOU	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Residential	PTR	Summer	0.0%	1.2%	1.2%	1.2%	1.1%
Residential	PTR w/Tech	Summer	0.0%	0.4%	0.4%	0.3%	0.3%
Residential	CPP	Summer	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Summer	0.0%	0.3%	0.3%	0.3%	0.2%
Residential	BYOT - AC	Summer	0.1%	1.2%	1.2%	1.2%	1.2%
Residential	BYOT - Space Heating	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - AC/Space Heating	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Residential	Smart Water Heater DLC	Summer	0.0%	0.2%	0.5%	0.8%	1.1%
Residential	Electric Vehicle DLC	Summer	0.0%	0.0%	0.1%	0.1%	0.2%
Small C&I	AC DLC	Summer	0.0%	0.4%	0.4%	0.4%	0.4%
Small C&I	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Water Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Summer	0.1%	1.3%	1.3%	1.3%	1.4%
Medium C&I	Curtailable Tariff	Summer	0.7%	0.7%	0.7%	0.7%	0.7%
Medium C&I	CPP	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Medium C&I	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Summer	0.2%	1.7%	1.8%	1.9%	1.9%
Large C&I	Curtailable Tariff	Summer	2.1%	2.2%	2.3%	2.4%	2.5%
Large C&I	CPP	Summer	0.0%	0.3%	0.3%	0.3%	0.4%
Large C&I	CPP w/Tech	Summer	0.0%	0.8%	0.9%	0.9%	0.9%
Agricultural	Pumping Load Control	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0	61.7	62.8	64.1	65.2
Residential	PTR	Winter	0.0	136.2	138.9	141.8	144.1
Residential	PTR w/Tech	Winter	0.0	24.6	25.0	25.6	26.0
Residential	CPP	Winter	0.0	109.4	111.3	113.6	115.5
Residential	CPP w/Tech	Winter	0.0	21.2	21.6	22.1	22.4
Residential	Behavioral DR	Winter	65.6	54.6	55.7	56.9	57.9
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0	0.5	0.5	0.5	0.6
Small C&I	PTR	Winter	0.0	1.7	1.8	1.9	2.0
Small C&I	PTR w/Tech	Winter	0.0	2.7	2.9	3.1	3.3
Small C&I	CPP	Winter	0.0	0.8	0.9	0.9	1.0
Small C&I	CPP w/Tech	Winter	0.0	1.6	1.7	1.8	1.9
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0	18.1	19.2	20.7	22.0
Medium C&I	CPP w/Tech	Winter	0.0	31.8	33.9	36.5	38.8
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0	35.4	38.2	41.6	44.7
Large C&I	CPP w/Tech	Winter	0.0	72.5	78.4	85.5	91.7
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	Space Heating DLC	Winter	2.3	20.1	21.2	22.4	23.3
Residential	Water Heating DLC	Winter	7.2	61.9	64.5	67.6	70.4
Residential	AC/Space Heating DLC	Winter	1.7	15.4	16.2	17.1	17.9
Residential	TOU	Winter	0.0	33.0	34.3	35.0	35.6
Residential	PTR	Winter	0.0	61.0	63.4	64.7	65.8
Residential	PTR w/Tech	Winter	0.0	13.4	13.9	14.2	14.5
Residential	CPP	Winter	0.0	45.4	47.2	48.2	49.0
Residential	CPP w/Tech	Winter	0.0	10.0	10.4	10.6	10.8
Residential	Behavioral DR	Winter	1.6	13.6	13.9	14.2	14.5
Residential	BYOT - AC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - Space Heating	Winter	1.4	12.6	13.2	14.0	14.6
Residential	BYOT - AC/Space Heating	Winter	1.1	9.6	10.1	10.7	11.2
Residential	Smart Water Heater DLC	Winter	0.2	15.1	41.1	67.5	88.9
Residential	Electric Vehicle DLC	Winter	0.3	0.9	2.0	3.5	5.0
Small C&I	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Small C&I	Space Heating DLC	Winter	0.7	6.0	6.5	7.1	7.5
Small C&I	Water Heating DLC	Winter	0.2	1.3	1.4	1.5	1.6
Small C&I	AC/Space Heating DLC	Winter	0.5	4.3	4.6	5.0	5.3
Small C&I	TOU	Winter	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Winter	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Winter	0.0	0.9	1.0	1.1	1.1
Small C&I	CPP	Winter	0.0	0.3	0.3	0.3	0.4
Small C&I	CPP w/Tech	Winter	0.0	0.4	0.5	0.5	0.6
Medium C&I	Third-Party DLC	Winter	4.2	38.1	40.9	44.1	46.8
Medium C&I	Curtailable Tariff	Winter	19.0	20.3	21.8	23.5	25.0
Medium C&I	CPP	Winter	0.0	5.0	5.5	5.9	6.3
Medium C&I	CPP w/Tech	Winter	0.0	9.0	9.8	10.6	11.2
Large C&I	Third-Party DLC	Winter	6.0	54.3	59.2	64.5	69.2
Large C&I	Curtailable Tariff	Winter	64.3	69.5	75.7	82.6	88.6
Large C&I	CPP	Winter	0.0	9.8	10.9	11.9	12.8
Large C&I	CPP w/Tech	Winter	0.0	25.6	28.4	31.0	33.2
Agricultural	Pumping Load Control	Winter	0.0	0.0	0.0	0.0	0.0
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)
Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR	Winter	0.0%	3.7%	3.6%	3.5%	3.4%
Residential	PTR w/Tech	Winter	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Winter	0.0%	3.0%	2.9%	2.8%	2.7%
Residential	CPP w/Tech	Winter	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Winter	1.8%	1.5%	1.4%	1.4%	1.4%
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0%	0.5%	0.5%	0.5%	0.5%
Medium C&I	CPP w/Tech	Winter	0.0%	0.9%	0.9%	0.9%	0.9%
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0%	1.0%	1.0%	1.0%	1.1%
Large C&I	CPP w/Tech	Winter	0.0%	2.0%	2.0%	2.1%	2.2%
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)
Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Space Heating DLC	Winter	0.1%	0.5%	0.5%	0.6%	0.6%
Residential	Water Heating DLC	Winter	0.2%	1.7%	1.7%	1.7%	1.7%
Residential	AC/Space Heating DLC	Winter	0.0%	0.4%	0.4%	0.4%	0.4%
Residential	TOU	Winter	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	PTR	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR w/Tech	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	CPP	Winter	0.0%	1.2%	1.2%	1.2%	1.2%
Residential	CPP w/Tech	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	BYOT - AC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	BYOT - AC/Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Smart Water Heater DLC	Winter	0.0%	0.4%	1.1%	1.7%	2.1%
Residential	Electric Vehicle DLC	Winter	0.0%	0.0%	0.1%	0.1%	0.1%
Small C&I	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Space Heating DLC	Winter	0.0%	0.2%	0.2%	0.2%	0.2%
Small C&I	Water Heating DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	0.1%	1.0%	1.1%	1.1%	1.1%
Medium C&I	Curtailable Tariff	Winter	0.5%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	CPP w/Tech	Winter	0.0%	0.2%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Winter	0.2%	1.5%	1.5%	1.6%	1.6%
Large C&I	Curtailable Tariff	Winter	1.8%	1.9%	2.0%	2.0%	2.1%
Large C&I	CPP	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	CPP w/Tech	Winter	0.0%	0.7%	0.7%	0.8%	0.8%
Agricultural	Pumping Load Control	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Benefit-Cost Ratios

Opt-out Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	N/A
Residential	Space Heating DLC	N/A
Residential	Water Heating DLC	N/A
Residential	AC/Space Heating DLC	N/A
Residential	TOU	1.24
Residential	PTR	1.49
Residential	PTR w/Tech	0.86
Residential	CPP	1.15
Residential	CPP w/Tech	0.83
Residential	Behavioral DR	1.04
Residential	BYOT - AC	N/A
Residential	BYOT - Space Heating	N/A
Residential	BYOT - AC/Space Heating	N/A
Residential	Smart Water Heater DLC	N/A
Residential	Electric Vehicle DLC	N/A
Small C&I	AC DLC	N/A
Small C&I	Space Heating DLC	N/A
Small C&I	Water Heating DLC	N/A
Small C&I	AC/Space Heating DLC	N/A
Small C&I	TOU	0.11
Small C&I	PTR	0.30
Small C&I	PTR w/Tech	0.82
Small C&I	CPP	0.11
Small C&I	CPP w/Tech	0.60
Medium C&I	Third-Party DLC	N/A
Medium C&I	Curtailable Tariff	N/A
Medium C&I	CPP	4.80
Medium C&I	CPP w/Tech	1.76
Large C&I	Third-Party DLC	N/A
Large C&I	Curtailable Tariff	N/A
Large C&I	CPP	42.10
Large C&I	CPP w/Tech	7.15
Agricultural	Pumping Load Control	N/A
Agricultural	TOU	0.83

Benefit-Cost Ratios

Opt-in Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	1.12
Residential	Space Heating DLC	1.31
Residential	Water Heating DLC	1.30
Residential	AC/Space Heating DLC	1.82
Residential	TOU	1.24
Residential	PTR	1.75
Residential	PTR w/Tech	1.32
Residential	CPP	1.62
Residential	CPP w/Tech	1.49
Residential	Behavioral DR	0.85
Residential	BYOT - AC	1.94
Residential	BYOT - Space Heating	1.98
Residential	BYOT - AC/Space Heating	2.43
Residential	Smart Water Heater DLC	2.22
Residential	Electric Vehicle DLC	0.14
Small C&I	AC DLC	1.00
Small C&I	Space Heating DLC	1.07
Small C&I	Water Heating DLC	0.79
Small C&I	AC/Space Heating DLC	1.40
Small C&I	TOU	0.06
Small C&I	PTR	0.17
Small C&I	PTR w/Tech	0.79
Small C&I	CPP	0.08
Small C&I	CPP w/Tech	0.55
Medium C&I	Third-Party DLC	1.59
Medium C&I	Curtailable Tariff	5.37
Medium C&I	CPP	1.94
Medium C&I	CPP w/Tech	1.38
Large C&I	Third-Party DLC	1.57
Large C&I	Curtailable Tariff	6.30
Large C&I	CPP	14.42
Large C&I	CPP w/Tech	6.70
Agricultural	Pumping Load Control	0.78
Agricultural	TOU	0.29