Estimating the impact of innovative rate designs

PRESENTED TO

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Principal

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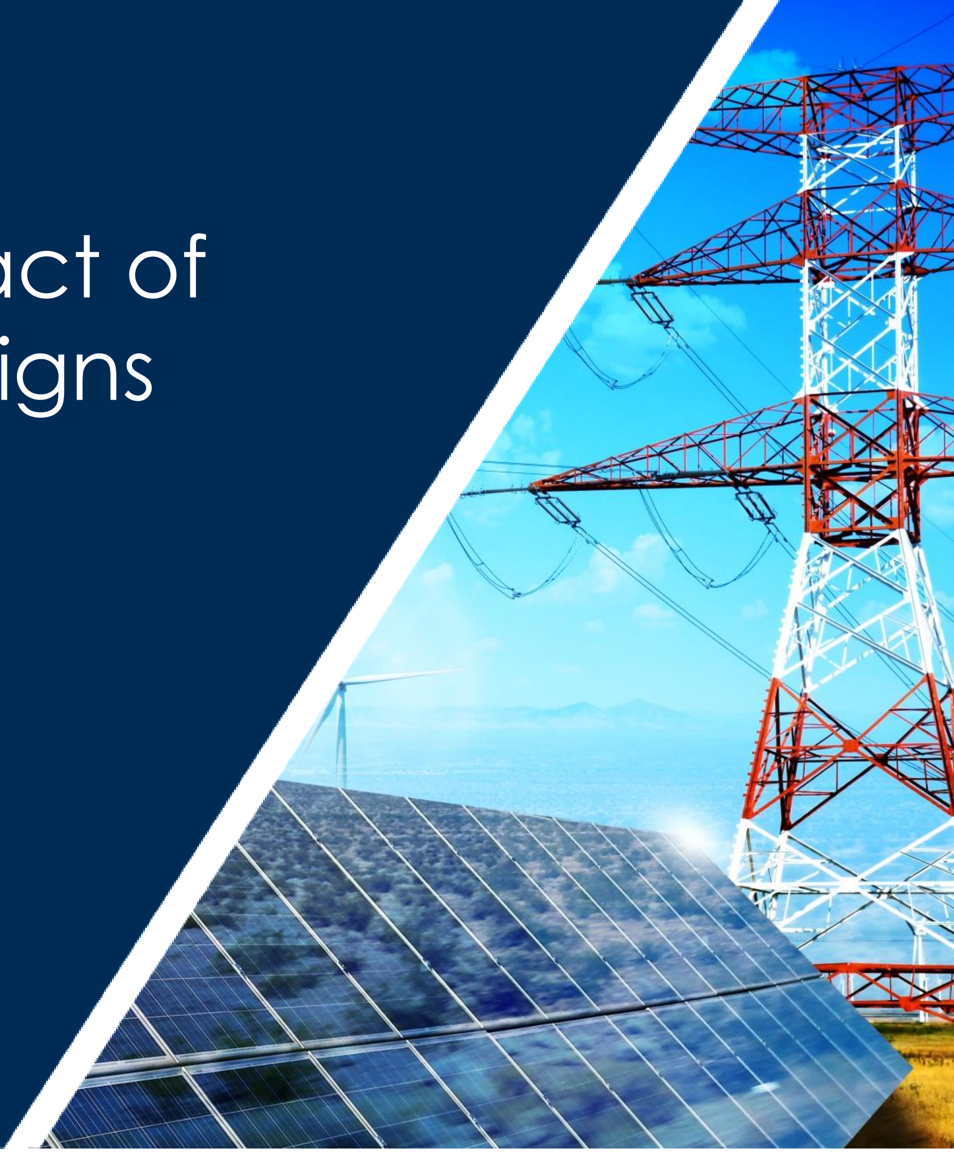


THE Brattle GROUP

Using “design thinking,” a few utilities are beginning to offer innovative rate choices

A Guaranteed bill (GB)

B GB with discounts for demand response (DR)

C Standard tariff

D Increased fixed charge(|FC)

E Demand charge

F Time-of-Use (TOU)

G Critical peak pricing (CPP)

H Peak time rebates (PTR)

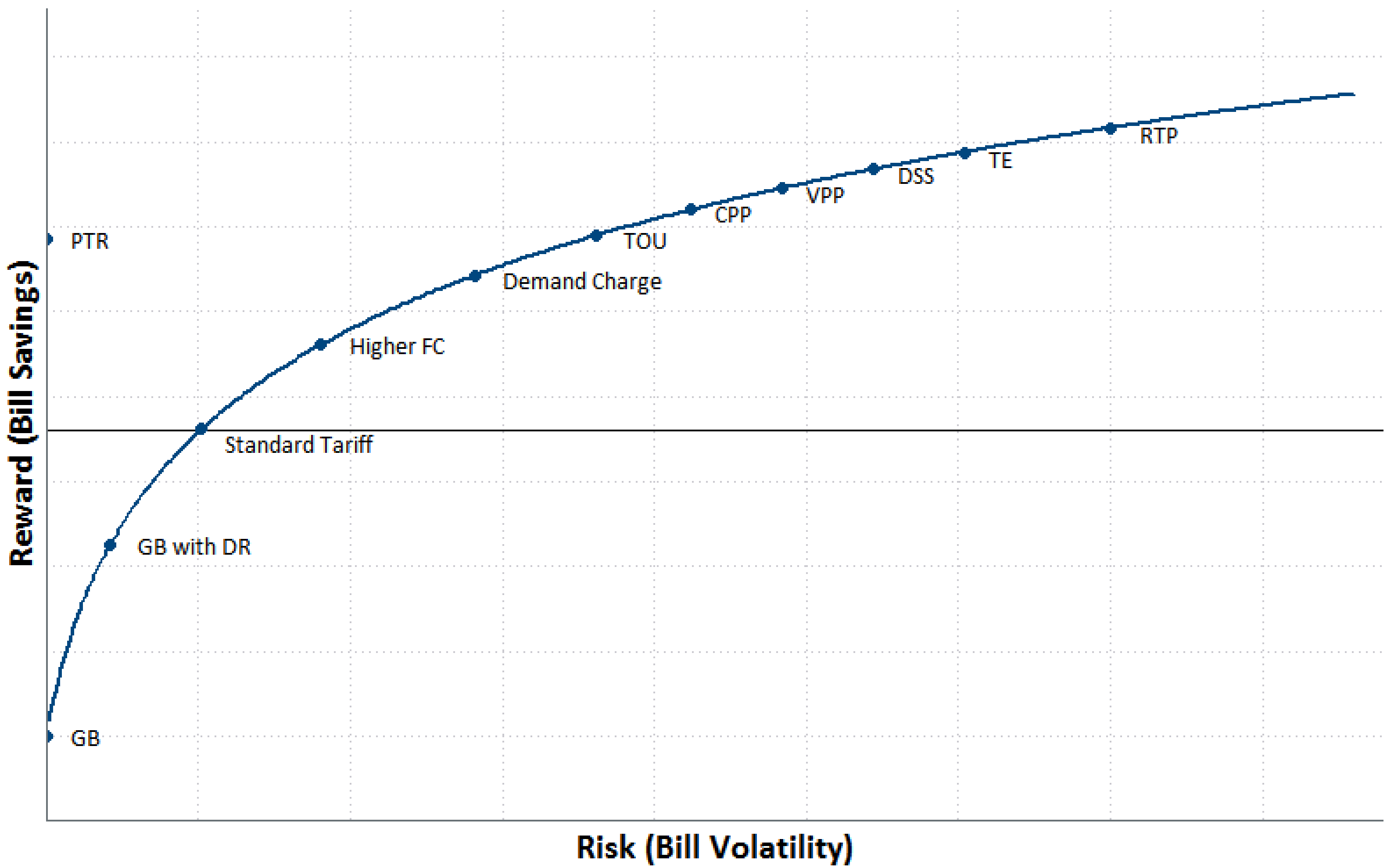
I Variable peak pricing (VPP)

J Demand subscription service (DSS)

K Transactive energy (TE)

L Real-time pricing (RTP)

These create an efficient pricing frontier, and customers can get what they want



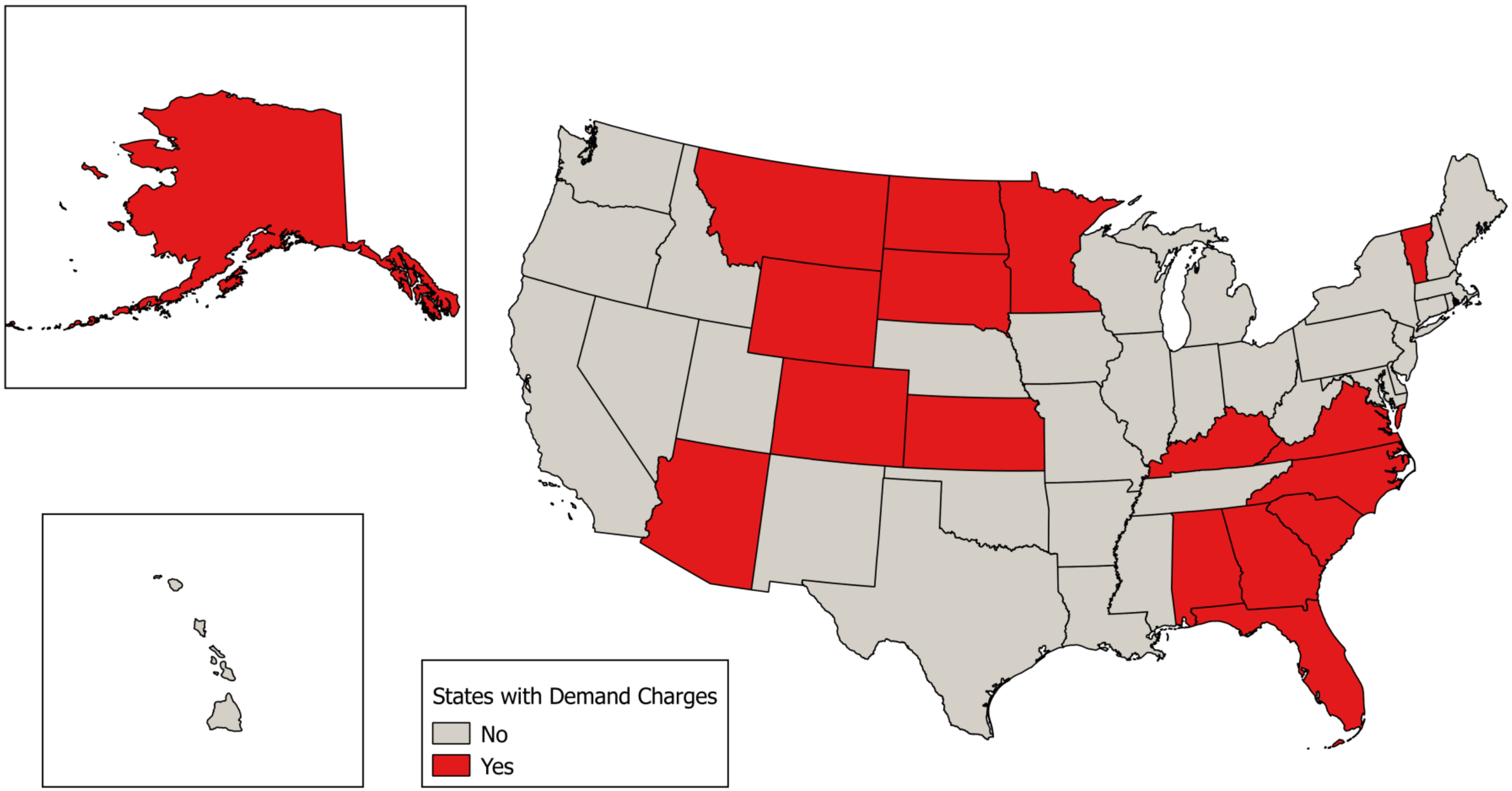
Ontario, Canada deployed TOU rates as the default about a decade ago

The deployment created some unique EM&V challenges which I will discuss later

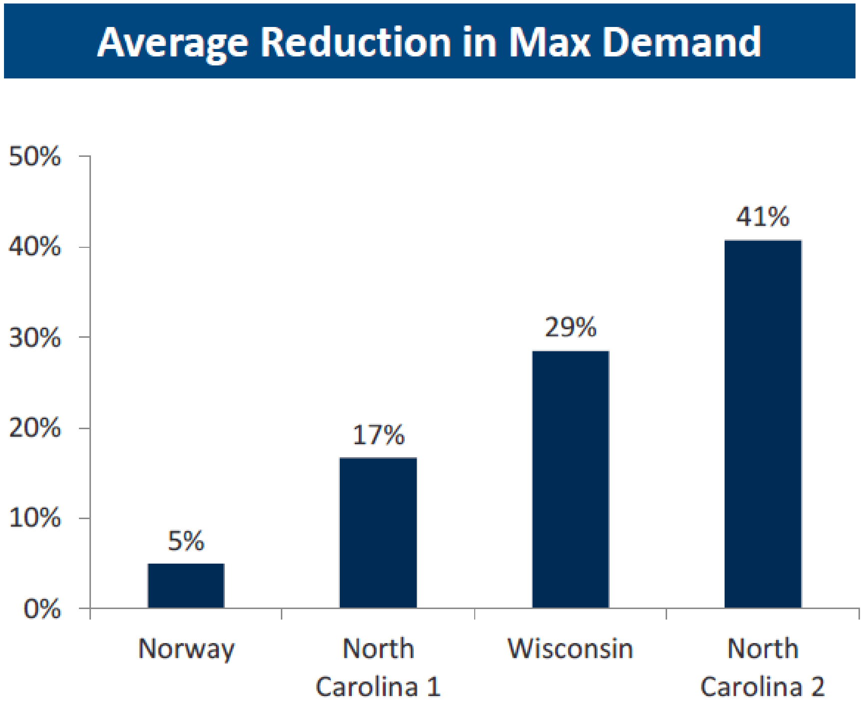
The TOU rate only applied to the energy portion of the rate

The peak to off-peak ratio was quite modest (about 1.4:1) but even then the class peak went down by approximately 2.5%

Over 30 utilities in 17 states offer residential demand charges



Three experiments have detected significant response to demand charges



Note: North Carolina was analyzed through two separate studies using different methodologies; both results are presented here

However…

- Two of the pilots are old and the third is from a unique climate
- The impact estimates vary widely
- Findings are based on small sample sizes
- New research is needed

There are three approaches to estimating customer response to new rate structures

Pilot approach

- The best method for empirically estimating customer response
- Features a control and a treatment group exposed to the new rate
- Random selection of treatment and control group can be done through a variety of ways (discussed later)

PRISM simulation approach

- The best method for estimating customer response *in the absence* of empirical data
- Response is estimated using 15-minute interval billing data and a system of two demand equations

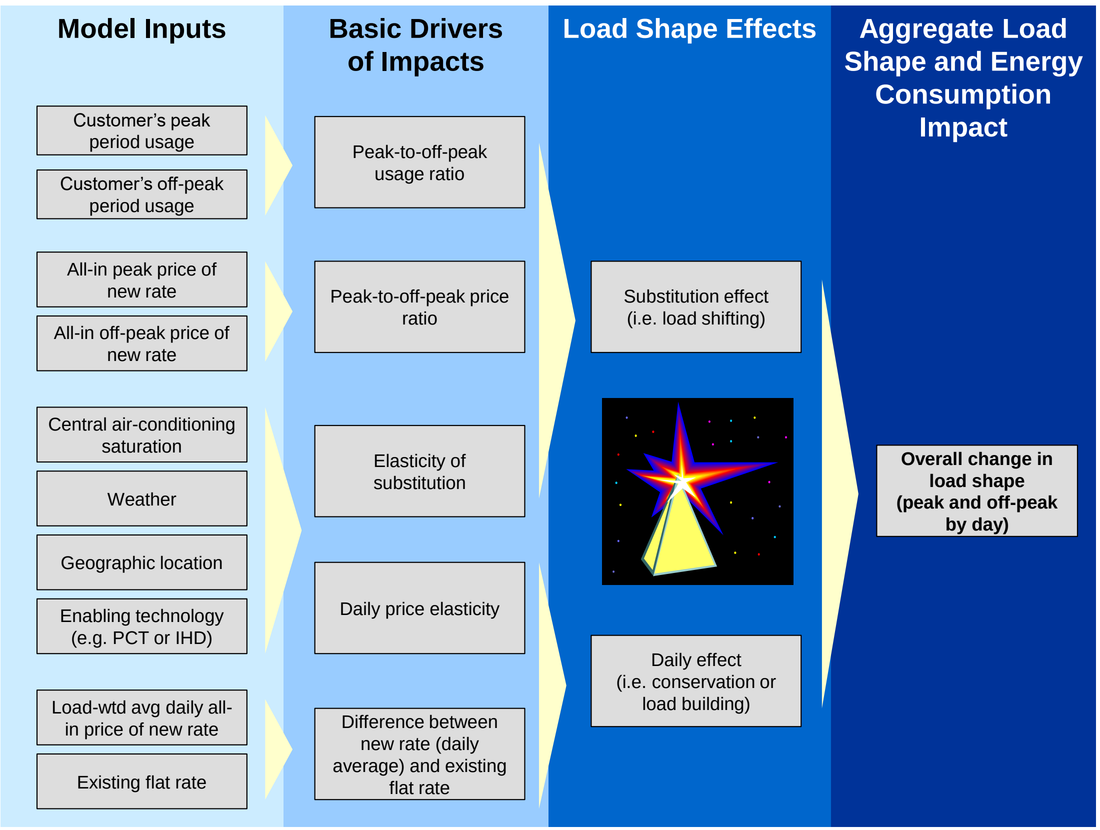
Arc-based approach

- A good approximation of customer response based on 60+ residential pricing pilots

PRISM System-based approach

PRISM: A system-based approach

Illustration of System-based Approach

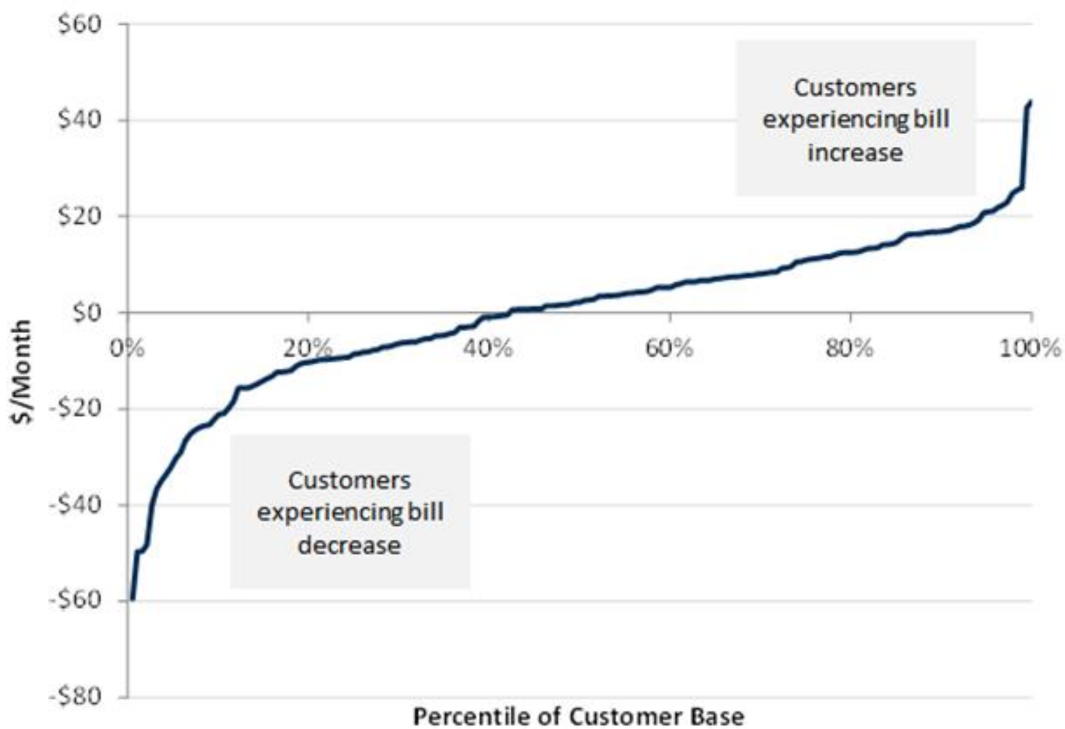


Comments

- Load shifting effect and the average price effect can be represented through a single system of two simultaneous demand equations
- The system of equations includes an "elasticity of substitution" and a "daily price elasticity" to account for these two effects
- There is support for this modelling framework in economic academic literature and it has been used to estimate customer response to time-varying rates in California, Connecticut, Florida, Maryland, and Michigan, among other jurisdictions
- In California and Maryland, the resulting estimates of peak demand reductions were used in utility AMI business cases that were ultimately approved by the respective state regulatory commissions

PRISM uses 15-min billing data to estimate impacts at the customer-level

Illustration of PRISM Model Output



Comments

- PRISM uses granular customer billing data to estimate demand for each customer during each hour of the day
- Because PRISM estimates load-shifting and total energy usage at the customer-level, PRISM can summarize impacts for different tiers of energy users (high, low)
- PRISM also calculates bill impacts resulting from estimated customer response to the new rate structures

The flexibility of the system-based approach allows for estimation of different rate designs

PRISM is used to estimate customer response to several types of rate structures

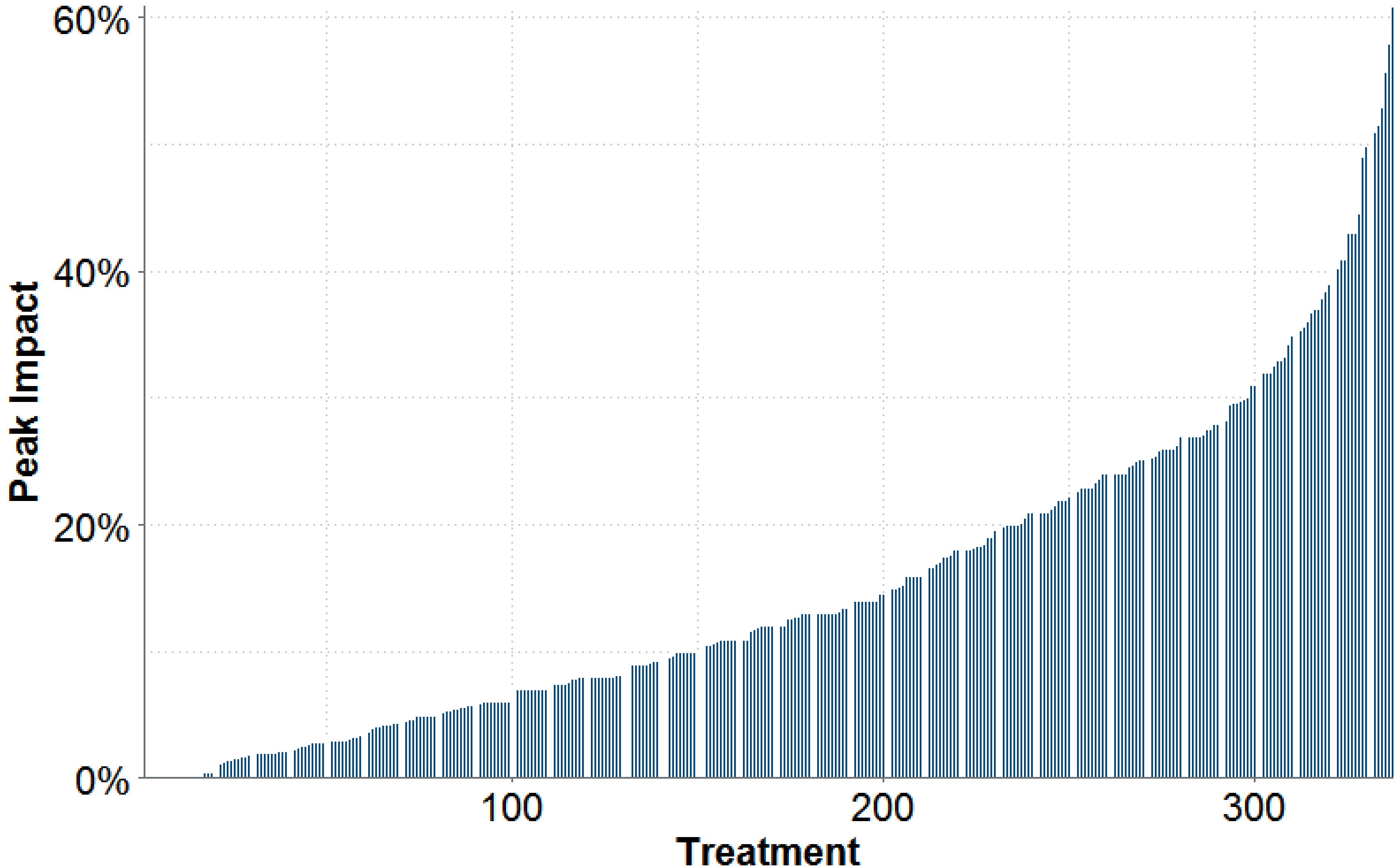
- TOU rates (two-period or three-period)
- Demand charges (with flat volumetric rate or time-varying)
- Inclining block-rates

Demand is mapped to a $/kWh rate using the customer's demand charge and the customer's peak usage

$$Mapped\ Demand\ Charge\ (\$/kWh) = \frac{Demand\ Charge\ (\$)}{Peak\ Usage\ (kWh)}$$

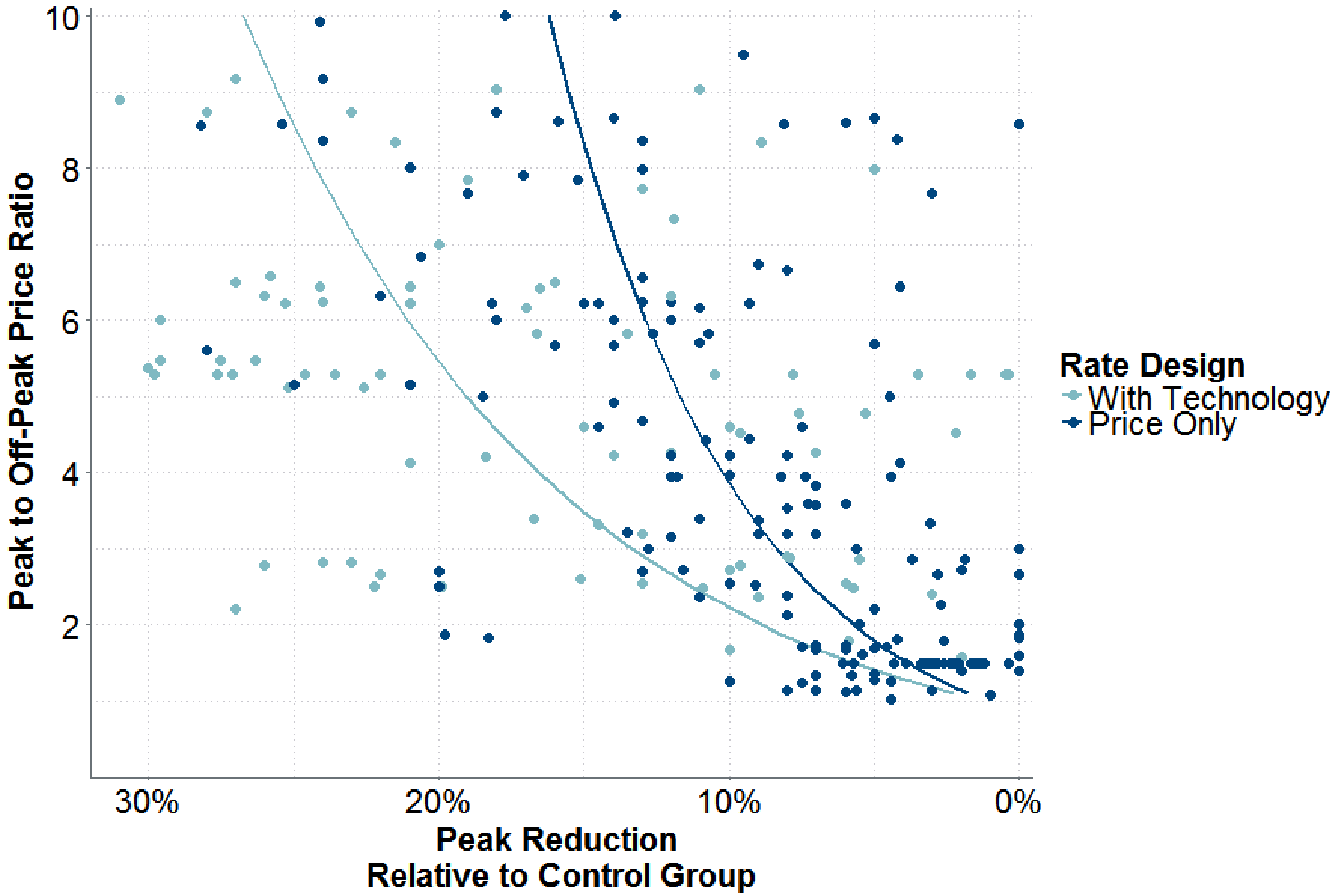
Arc-based approach

349 experiments have shown that customers respond to time-varying and dynamic pricing



Source: Ahmad Faruqui, Sanem Sergici and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal* 30, no. 10 (2017): 64-72.

Customer response can be expressed as a function of the price ratio



Source: Ahmad Faruqui, Sanem Sergici and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal* 30, no. 10 (2017): 64-72.

Arc-based approach leverages estimates from a large database of pricing pilots

The Arcturus database features 60+ residential pricing pilots

- Nearly 350 experimental pricing treatments
- Jurisdictions in three continents (Asia, Europe, and North America)
- Data on duration of peak period, number of participating customers, opt-in / opt-out enrollment, season of pilot, and more

Using simple linear regression, the Arc-based approach predicts:

- For a 10% increase in the peak-to-off-peak price ratio, peak usage will decline by 6.5%
- If the customer is provided with a smart thermostat, the effect instead is 11.1%
- If the rate is deployed on an opt-out basis, the effect is approximately four percent lower per participating customer but the aggregate impact may be higher because more customers are participating in the rate

Recent program design and evaluation developments

Our team undertook the impact evaluation of Ontario's full scale residential TOU program using data from 8 Local Distribution Companies representing more than 50% of electric accounts in Ontario, Canada

- Analysis was carried out using data for three years
- Estimated generalized addilog system to measure impacts and estimate substitution elasticities
- Impacts were allowed to vary by socio demographic factors

We are currently undertaking an analysis for the Ontario Energy Board investigating the load impacts resulting from five foundational hourly pricing archetypes and will quantify the economic benefits of switching to these rates from the status quo TOU rates

Maryland is initiating new TOU pilots

Pepco	Current (Flat)	On-Peak	Off-Peak	Ratio
Delivery Service Charges	$0.04051	$0.16165	$0.01989	8.1
Supply Charges	$0.08258	$0.17706	$0.06650	2.7
Total	$0.12309	$0.33871	$0.08639	3.9

Three design approaches were considere

Possible Pilot Design Approaches	Description and Pros/Cons
Randomized Control Trial (RCT)	Involves a random assignment of the recruited customers into the treatment and control groups. Even though it is the most rigorous approach from a measurement perspective, it is rarely used by electric utilities due to a potentially adverse impact on customer satisfaction (as it would involve one of the recruit-and-deny or recruit-and-delay approaches).
Randomized Encouragement Design (RED)	Allows the researcher to construct a valid control group, maintaining the benefits of an RCT design by not negatively affecting the customer experience. However, it requires much larger sample sizes compared to RCT in order to be able to detect a statistically significant impact. Large sample sizes increase the pilot implementation costs.
Random Sampling With Matched Control Group	Involves recruiting treatment customers from a randomly selected sample, and using a regression analysis to identify and match customers from the rest of the population that are most similar to the treatment customers. This matched control group approach strikes a good balance between achieving statistically valid results and requiring a manageable level of pilot participants.

Brattle verified the benefits of AMI investments post-deployment for PHI utilities

Our team has quantified the impact of AMI enabled energy management tools on customer usage in four PHI jurisdictions

We undertook a novel econometric analysis quantifying the conservation impact of conservation voltage reduction (CVR) for two PHI jurisdictions

We are currently assisting the Maryland utilities in the PC 44 Grid Modernization with the design of the SOS and delivery TOU rate pilot and will undertake EM&V once the pilots are underway

Conclusions

There is tremendous demand for testing and measuring the effects of new rate structures

- Advent of smart meters allows implementation and measurement of new rates
- In the fourth wave of pricing pilots, DERs and renewable penetration pushing the physical constraints of the grid

Using a control and a treatment group, pilots are the best way to test the impact of new rates, but they're costly

In the absence of empirical data, PRISM and Arc-based approaches are the next best methods for reliably estimating customer response

Institutional Background

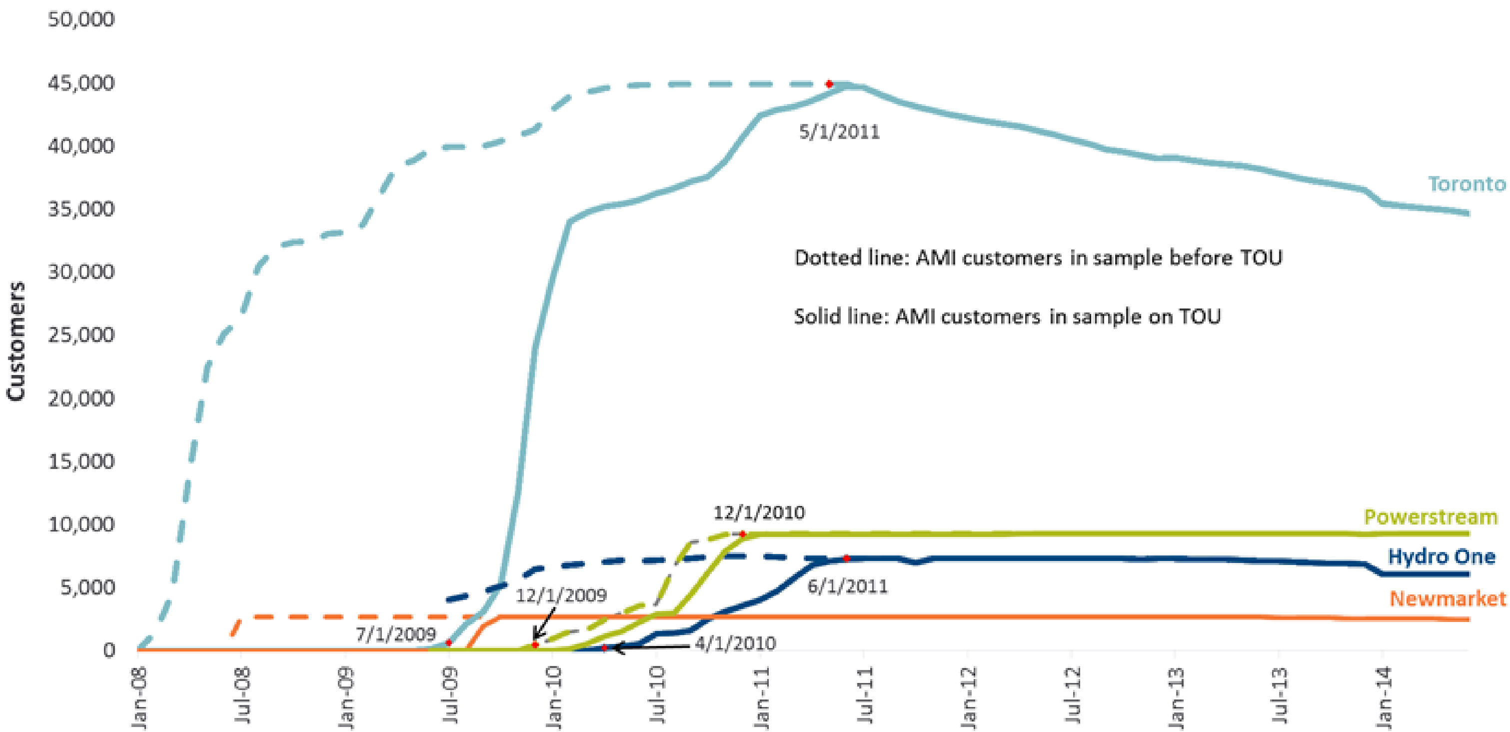
Ontario has 70+ Local Distribution Companies (LDCs)

- The Regulated Price Plan (RPP) offers TOU rates on a default basis
- Customers can opt-out of RPP by contracting with a retailer

Smart Metering Initiative announced by provincial government in 2004 required the LDCs required to

- Roll out smart meters by 2010
- Deploy TOU rates by 2012
- Migrate smart meter data to a centralized Meter Data Management and Repository (MDM/R) before TOU

Timing, Data and Challenges



For example: Central Region Rollout Schedule - Residential

total number of AMI customers in sample before TOU

total number of AMI customers in sample on TOU

Evaluation Challenges

Recruitment of LDCs

Disparate data sets

Statutory Environment

Non-experimental environment

Lessons Learned for Future TOU Rollouts

Plan the Rollout

Ensure Adequate Collection of and Access to New Data

Incentivize M&V Compliance

About the Study

Three year effort to measure load shifting and conservation impacts of TOU by calendar year

- All Impact Reports on IESO website

Examine three seasons and two customer classes

- Summer, Winter and IESO Evaluation Peak
- Residential and general service

Today's Results from Study Year 3

- Includes 8 LDCs
- Constitute more than 50% of Ontario electricity accounts.

Methodology

Use Generalized Addilog Demand System to measure impacts

- Structural Model – allows out of sample predictions
- Allows for substitution elasticities to vary between periods

Impacts calculated separately for each of four Ontario sub-regions

- Impacts allowed to vary by socio-demographic factors

Reweight regional impacts using census characteristics to obtain representative regional impacts

Province-wide impacts are calculated by weighting the regional impacts by regional customer count shares

Results

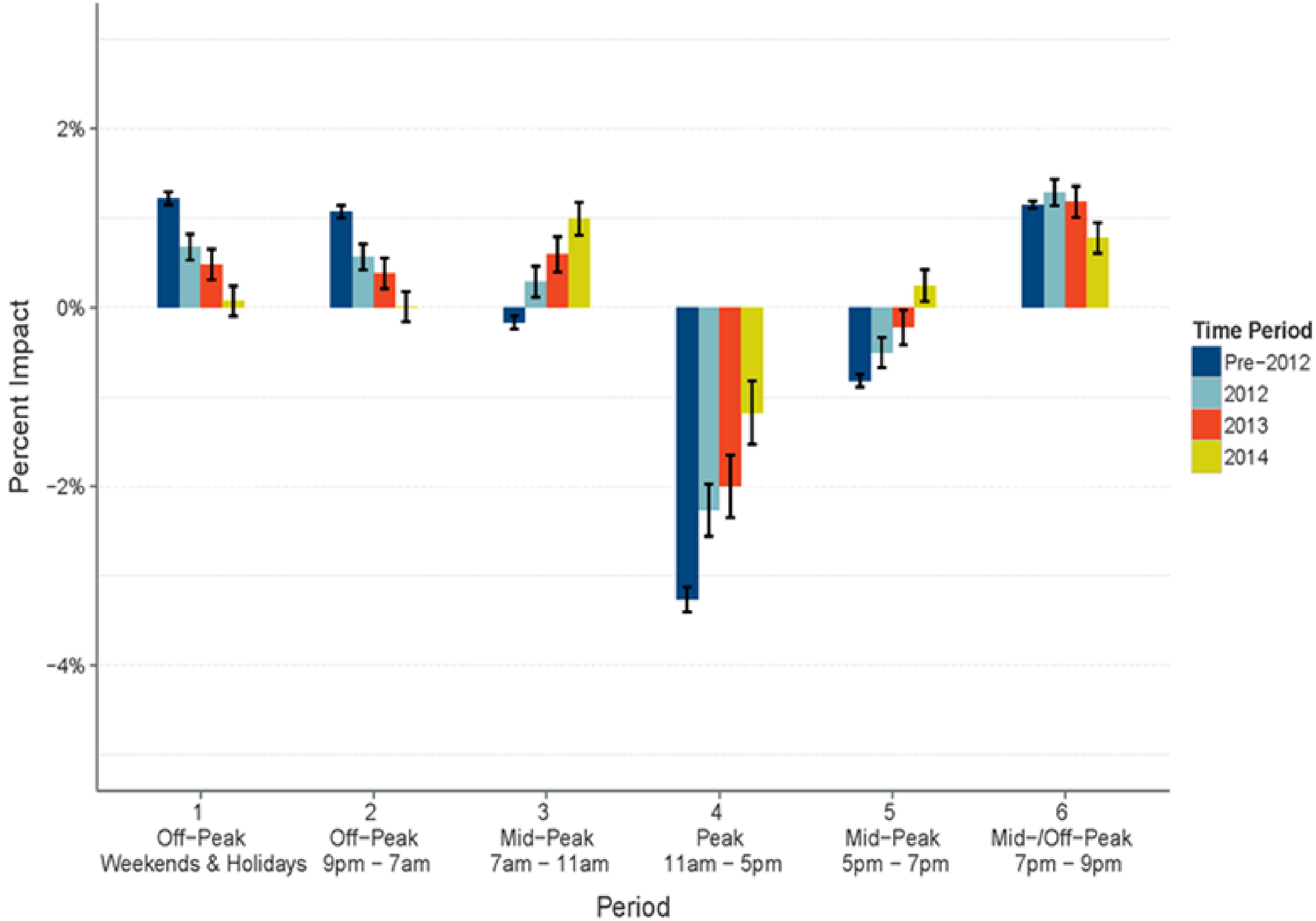
There is significant evidence of load shifting across all regions and years

- Reduction in usage in the peak period, some reduction in the mid-peak
- Increase in usage in the off-peak periods

The load shifting model parameters are generally well-behaved and have magnitudes that have been observed in other pilots

There are some unexpected, positive and significant elasticities in the conservation models, likely due to insufficient data history and little price variation

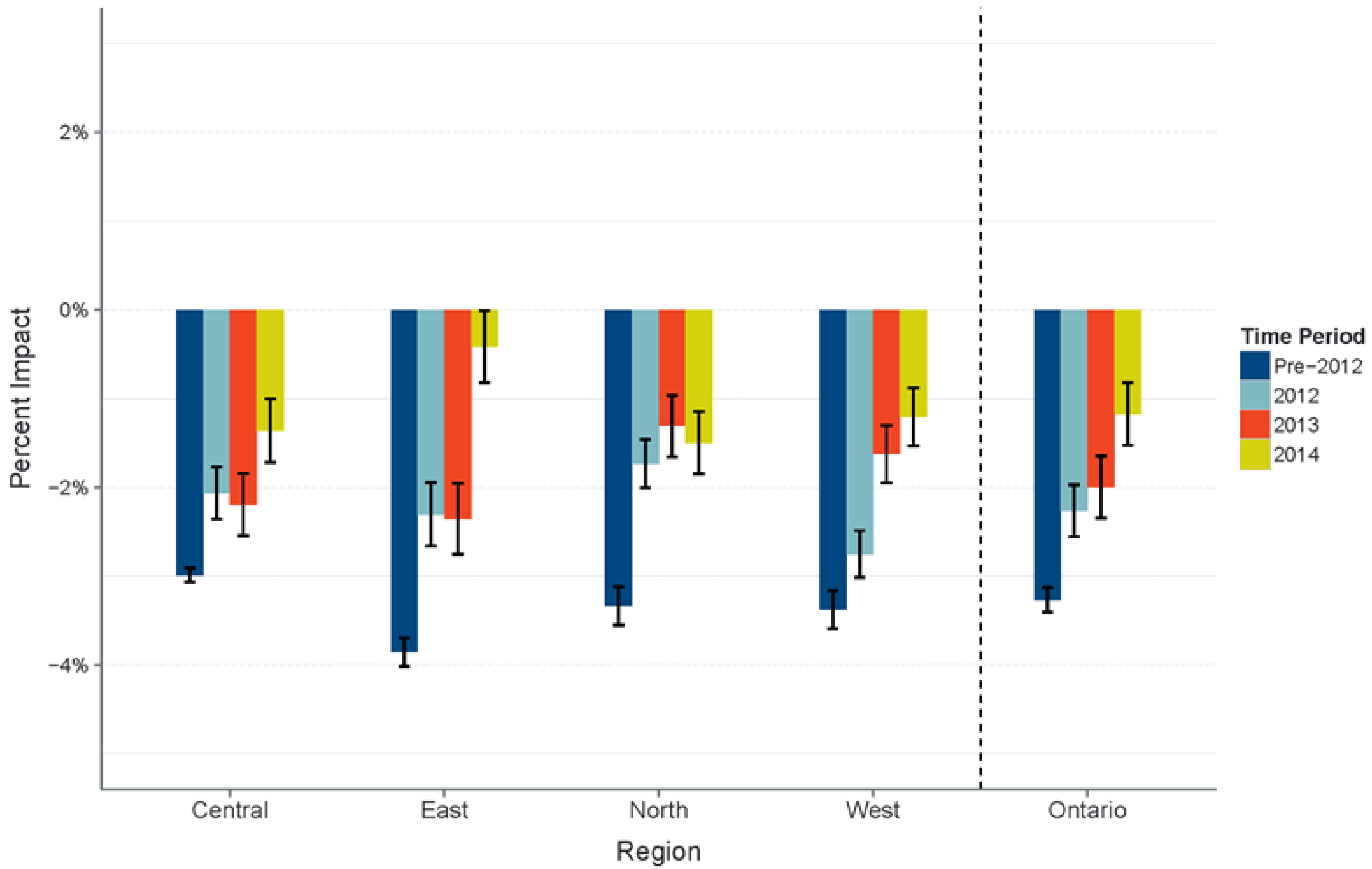
Residential Summer Load Shifting Across All Periods for Ontario



Province-Level Load Shifting Summer Residential

* Period 6 was mid-peak before May 2011
Note: Black bars indicate 95% confidence intervals for the impact

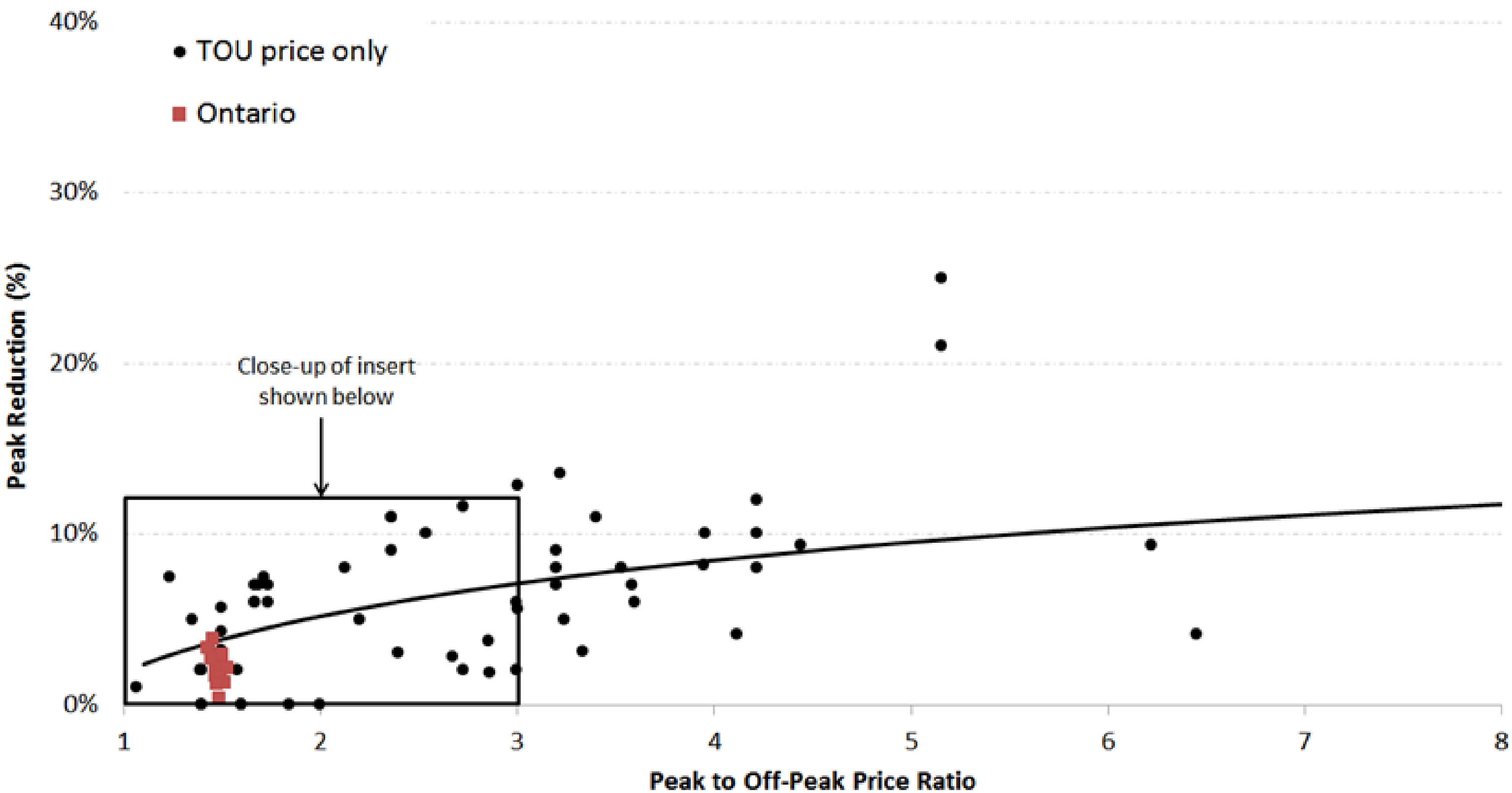
Residential TOU Peak Period Impacts across Regions



Summer TOU Peak Period (11am – 5pm)
Residential Load Shifting Results

Note: Black bars indicate 95% confidence intervals for the impact

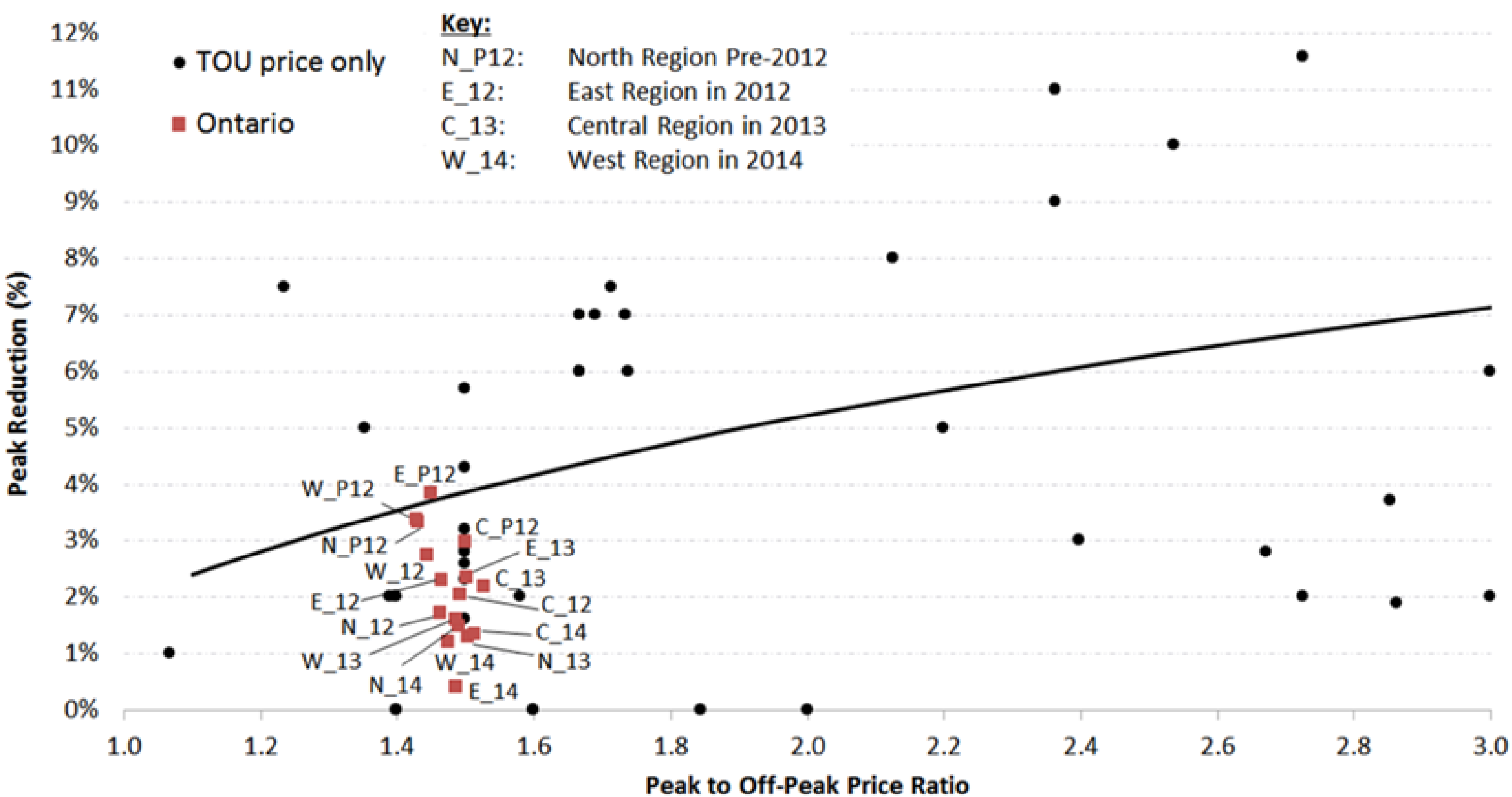
Ontario Residential TOU Impacts Compared to TOU Pilots from Around the Globe



Ontario Residential TOU Summer Impacts Compared to TOU Pilots from Around the World

All of the data points shown in blue above, are currently drawn from TOU pilot studies, not full scale rollouts like the OPA

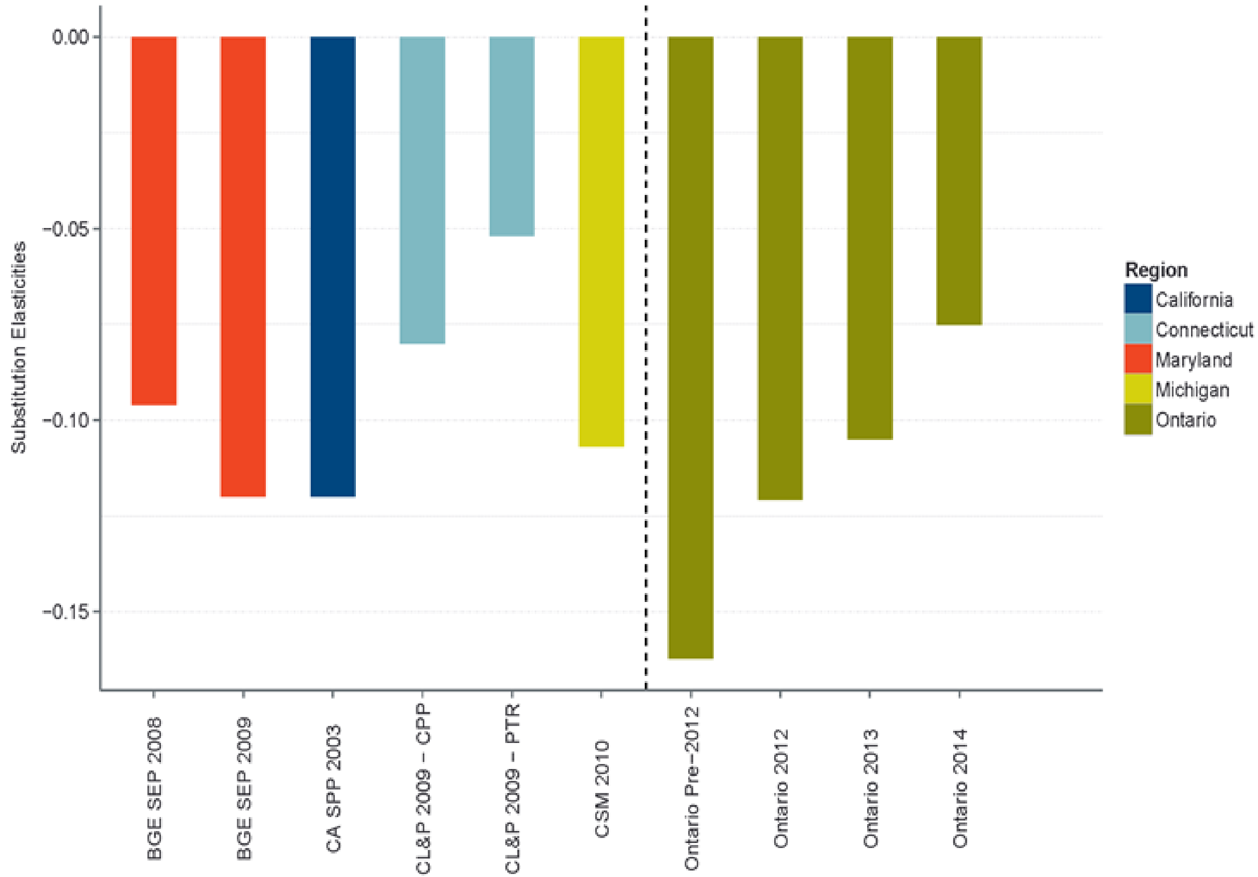
Ontario Residential TOU Impacts Compared to TOU Pilots from Around the Globe



Close-up of Ontario Residential TOU Summer Impacts Compared to TOU Pilots from Around the World

All of the data points shown in blue above, are currently drawn from TOU pilot studies, not full scale rollouts like the OPA

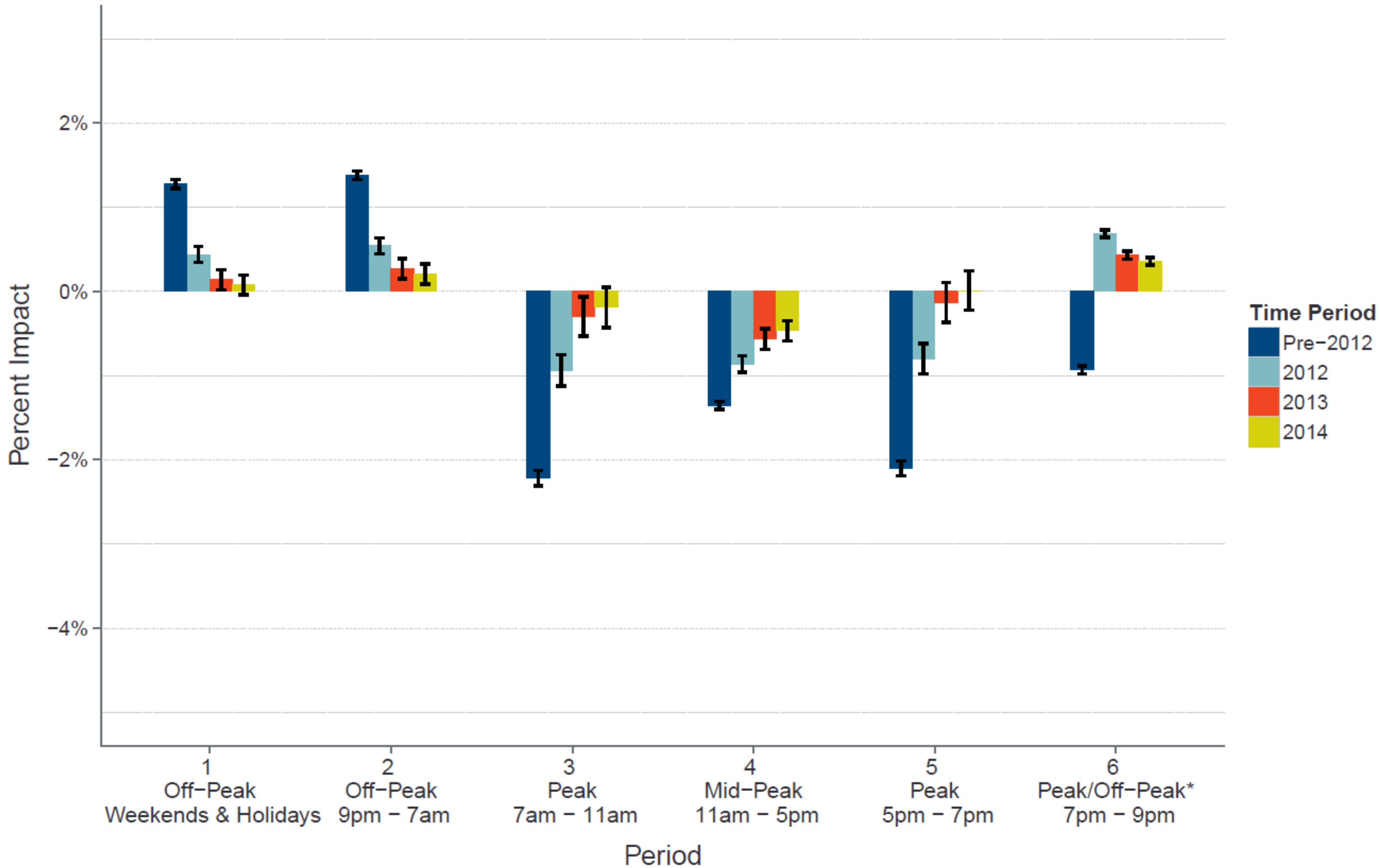
Residential Substitution Elasticities Compared to Pilot Studies Elsewhere*



Residential Substitution Elasticities Compared to Other Pilots (Summer TOU Peak Period)

* The Ontario TOU rollout was system wide, not a pilot

Residential Winter Load Shifting Across All Periods for Ontario



Provincial Winter Load Shifting for Residential

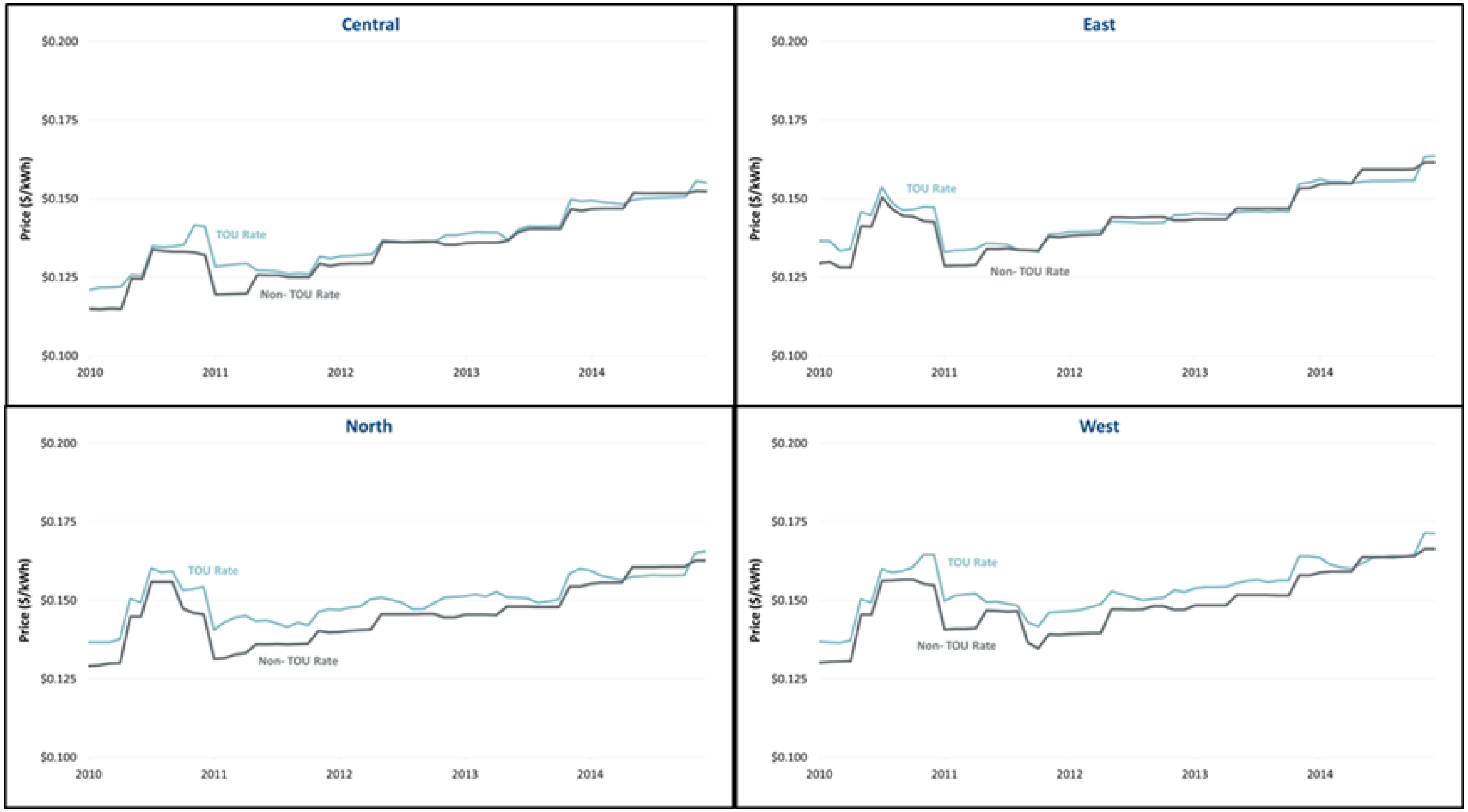
* Period 6 was peak before May 2011

Note: Black bars indicate 95% confidence intervals for the impact

Annual Residential Conservation Impacts by Region

We did not find any evidence of residential conservation due to the rollout of TOU rates

- There is very little variation in average prices over time



Residential TOU and Non-TOU Prices 2010-2014

Conclusions

By 2012 the province of Ontario had switched nearly 95% of residential customers to default TOU

We exploit variations in the timing of the rollout as well as the existence of non-TOU retail customers to estimate the load shifting and conservation impacts of TOU

Load shifting impacts are consistent with those found in other studies and relatively consistent across regions in Ontario and study years

We find no evidence of TOU induced conservation

Simulating customer response to demand charges with PRISM: A case study of Xcel Energy (Colorado)

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We use a hypothetical customer's June load profile when illustrating the three approaches

770 kWh of monthly electricity consumption

Time-differentiated consumption

- 70 kWh on peak (weekdays, 2 pm to 6 pm)
- 700 kWh off peak

IBR tier-differentiated consumption

- 500 kWh first tier
- 270 kWh second tier

3.5 kW of maximum demand

- Measured during peak hours
- Load factor of 30%

Converting the RD-TOU rate into an all-in TOU rate

As a first step in the Arc-based and System-based approaches, the RD-TOU rate is converted into an all-in TOU rate

Proposed Schedule RD-TOU

	Charge	Quantity	Bill
Service & facility charge ($/month)	9.53	1	$9.53
Grid use ($/month)	14.56	1	$14.56
Non-ECA riders ($/kW)	3.78	3.5	$13.23
ECA rider - peak ($/kWh)	0.035698	350	$12.49
ECA rider - off-peak ($/kWh)	0.028109	420	$11.81
Energy ($/kWh)	0.004610	770	$3.55
Demand ($/kW)	7.880000	3.5	$27.58
		Total:	**$92.75**

Notes:
Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

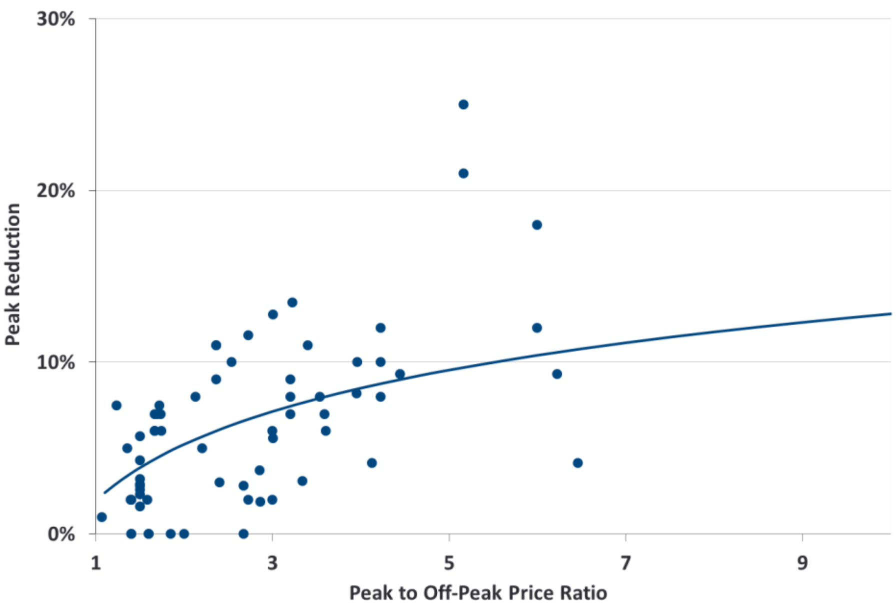
Levelized Prices

All-in Price	Peak	Off-Peak
Service & facility charge ($/kWh)	0.0130	0.0130
Grid use ($/kWh)	0.0199	0.0199
Non-ECA riders ($/kWh)	0.1518	0
ECA rider ($/kWh)	0.0357	0.0319
Energy ($/kWh)	0.0046	0.0046
Demand ($/kWh)	0.3165	0
Total ($/kWh)	**0.5415**	**0.0694**
All-in peak-to-off peak price ratio	**7.8**	

Notes:
Peak period is defined above as 2 pm to 6 pm, weekdays.
Due to a different peak definition in the ECA rider, the off-peak ECA rider price shown in the table is the load-weighted average of peak and off-peak ECA prices outside of the 2 pm to 6 pm window.

- Fixed charges are divided by the number of hours in the month and spread equally across all hours
- Demand charges are levelized and spread only across peak hours
- Volumetric charges remain unchanged

The Arc-based Approach



Note: Chart includes 67 data points from TOU pricing treatments without enabling technology.
The Arc was specified considering all 230 time-varying pricing treatments including CPP, VPP, PTR, and TOU.

- The results of 200+ pricing treatments across more than 40 pilots can be summarized according to the peak-to-off-peak price ratio of the rate and the associated measured peak reduction
- Focusing only on TOU pilots, we have fit a curve to these points to capture the relationship between price ratio and price response
- The drop in peak period usage can be read off the graph using the price ratio from the all-in TOU equivalent of the RD-TOU rate (as summarized on previous slide)
- For further discussion, see Ahmad Faruqui and Sanem Sergici, “Arcturus: International Evidence on Dynamic Pricing,” *The Electricity Journal*, August/September 2013.

The Arc-based Approach (cont'd)

Current Schedule R

	Charge	Quantity	Bill
Service & facility charge ($/month)	6.75	1	$6.75
Non-ECA riders ($/kWh)	0.01156	770	$8.90
ECA rider ($/kWh)	0.03128	770	$24.09
Energy - first 500 kWh ($/kWh)	0.04604	500	$23.02
Energy - 500+ kWh ($/kWh)	0.09000	270	$24.30
		Total:	**$87.06**

Proposed Schedule RD-TOU

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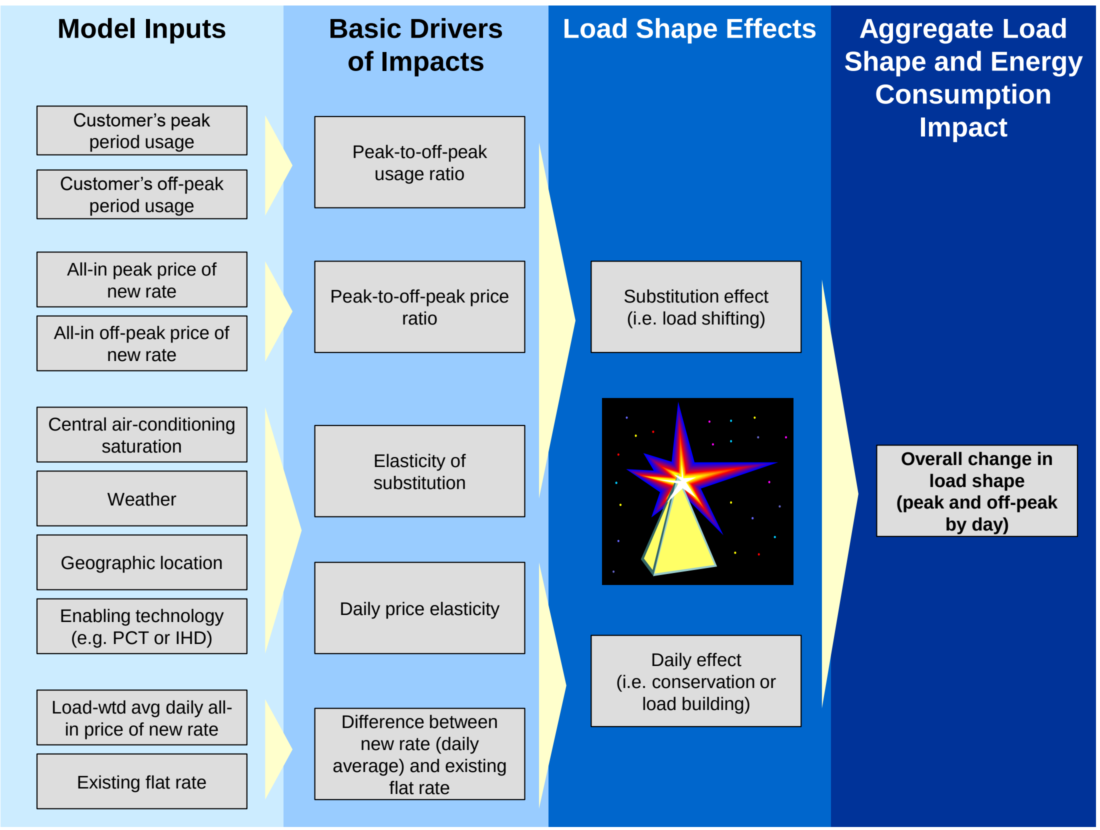
		Total:	**$92.75**

Notes:
Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

- The Arc-based Approach also accounts for customer response to a change in their average rate level
- For instance, if a customer's bill increases under the RD-TOU rate absent any change in consumption, that customer is likely to respond by reducing their overall energy use (including during the peak period)
- In this example, the hypothetical customer's total bill increases by 6.5% with the new rate
- Total electricity consumption would decrease as a result, based on an assumed price elasticity
- For example, with a price elasticity of -0.20, consumption would decrease by 1.3%
- We assume the same percentage change to consumption in all hours
- This effect is combined with the load shifting effect described on the previous slides to arrive at the composite change in load shape for each individual customer

The System-based Approach



- As an alternative to the two steps in the Arc-based Approach, the load shifting effect and the average price effect can be represented through a single system of two simultaneous demand equations
- The system of equations includes an "elasticity of substitution" and a "daily price elasticity" to account for these two effects
- There is support for this modeling framework in economic academic literature and it has been used to estimate customer response to time-varying rates in California, Connecticut, Florida, Maryland, and Michigan, among other jurisdictions
- In California and Maryland, the resulting estimates of peak demand reductions were used in utility AMI business cases that were ultimately approved by the respective state regulatory commissions

The Pilot-based Approach

In the Pilot-based Approach, the reduction in peak period demand is based on an average of the empirical results of the following three residential demand charge studies

Study	Location	Utility	Year(s)	# of participants	Monthly demand charge ($/kW)	Energy charge (cents/kWh)	Fixed charge ($/month)	Timing of demand measurement	Interval of demand measurement	Peak period	Estimated avg reduction in peak period consumption
1	Norway	Istad Nett AS	2006	443	10.28	3.4	12.10	Peak coincident	60 mins	7 am to 4 pm	5%
2	North Carolina	Duke Power	1978 - 1983	178	10.80	6.4	35.49	Peak coincident	30 mins	1 pm to 7 pm	17%
3	Wisconsin	Wisconsin Public Service	1977-1978	40	10.13	5.8	0.00	Peak coincident	15 mins	8 am to 5 pm	29%

Notes:
All prices shown have been inflated to 2014 dollars
In the Norwegian pilot, demand is determined in winter months (the utility is winter peaking) and then applied on a monthly basis throughout the year.
The Norwegian demand rate has been offered since 2000 and roughly 5 percent of customers have chosen to enroll in the rate.
In the Duke pilot, roughly 10% of those invited to participate in the pilot agreed to enroll in the demand rate.
The Duke rate was not revenue neutral - it included an additional cost for demand metering.
The Wisconsin demand charge is seasonal; the summer charge is presented here because the utility is summer peaking.

- Based on the results of these pilots, the average peak period demand reduction for each customer is assumed to be **14%** (impacts of the Norway and North Carolina pilots are derated when calculating this average, as described later)
- To estimate the change in total consumption, we account for the effect of the change in average price in the same way that it is accounted for in the Arc-based approach; this is combined with the peak impact described above

Price elasticities of demand

Price elasticities represent the extent to which customers change consumption in response to a change in price

We assume a price elasticity of -0.2 when estimating the average price effect, based on a review of price elasticities estimated by Xcel Energy and assumptions in prior Brattle work

The System-based Approach uses an elasticity of substitution of -0.14 and a daily price elasticity of -0.04

- The daily elasticity is based on California's "Zone 3" which we believe most closely represents the conditions of Xcel Energy's Colorado service territory. The elasticity of substitution is based on pilot results in Boulder.

Derating peak impacts

A recent time-varying 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

The price elasticities in the Arc-based and System-based approaches are derived from pilots offered on an opt-in basis; since Xcel Energy is proposing to roll out the RD-TOU rate on a default or mandatory basis, we have derated the estimated impacts by 40% so that they are applicable to a full-scale default residential rate rollout

Similarly, in the Pilot-based Approach we derated the results of the Norway and North Carolina pilots by 40% since they both included opt-in participation. Results of the Wisconsin pilot were not derated, as we believe participation in that pilot was mandatory

Revenue neutrality

Several minor adjustments were made to the RD-TOU rate in order to make it revenue neutral to the current Schedule R rate for the load research sample

ECA rider

- Each customer's proposed ECA charge is multiplied by a constant so that revenue collected by the proposed ECA charge across all customers is equal to the revenue collected by the current ECA charge

Other riders (DSMCA, PCCA, CACJA, and TCA)

- Like the ECA rider, these charges in the RD-TOU rate are all scaled proportionally such that they produce in the aggregate the same revenue as the charges in the current rate

Production meter charge

- The production meter charge of $3.65/month is excluded from the RD-TOU rate to avoid accounting for the effect of a rate increase associated with advanced metering

Demand charge

- The demand charge remains unchanged relative to the rates provided by Xcel Energy

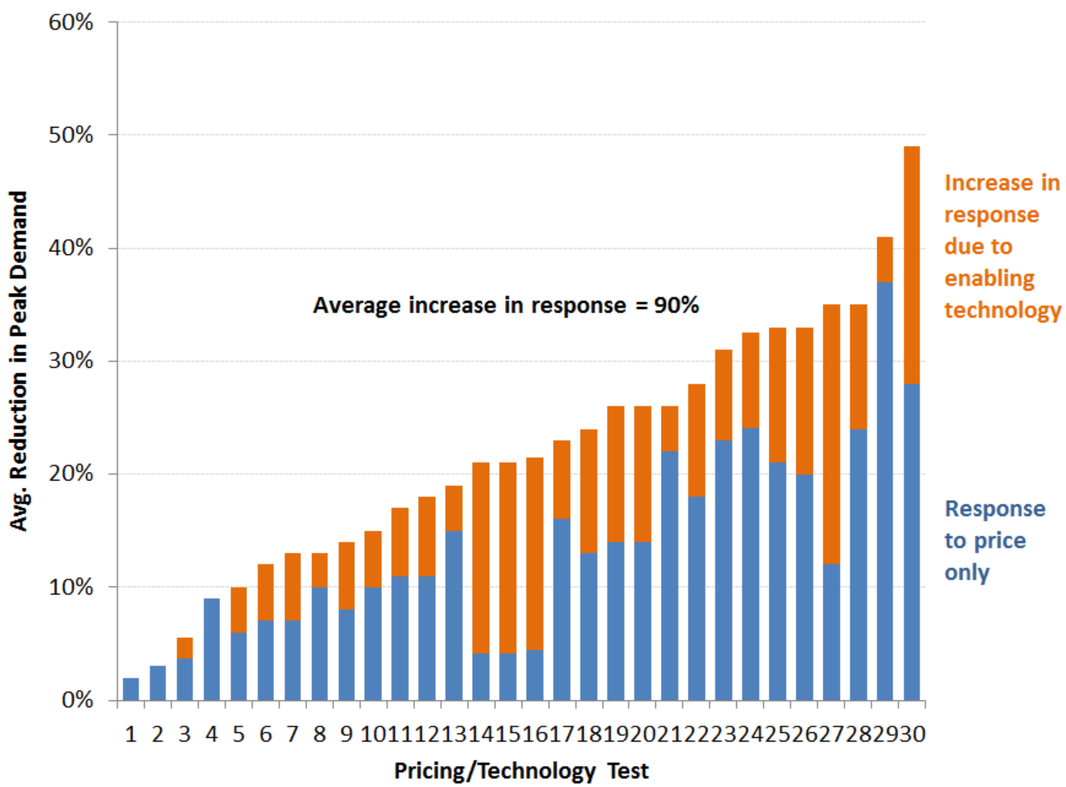
Energy charge

- The energy charge in the RD-TOU rate is adjusted to make up any remaining difference in revenue collected from the current rate and the proposed rate

Load research data

- Xcel Energy provided us with hourly load research data for 233 customers
- The hourly data covers the calendar year 2013
- In some cases, hourly observations were flagged in the dataset as meter reading errors – these were treated as "missing values" in our analysis.
- 15 customers were missing data for at least 5% of the hours in the year. These customers were removed from the sample.
- One customer had recorded usage of 0 kWh for over 60 consecutive days, but their usage was not flagged for errors. This customer was kept in the sample, and does not substantively impact the results.
- While the vast majority of customers had mean hourly usage of less than 5.8 kW, one customer had a mean hourly usage of 64 kW; this customer was flagged as an outlier and removed from the sample.
- After making all adjustments to the load research sample, we were left with 217 customers

The impact of technology



- Note that our analysis accounts only for behavioral response to the new rate; it does not account for technology-enabled response
- The introduction of a demand charge will provide customers with an incentive to adopt technologies that will allow them to reduce their peak demand for bill savings; batteries, demand limiters, and smart thermostats are three such examples
- Technology has been shown to significantly boost price response (as shown at left) and could lead to larger peak demand reductions than we have estimated in this analysis

Results - Monthly Detail

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Monthly change in class average peak period demand

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Peak Demand	**-5.6%**	**-13.4%**	**-11.6%**
January	-6.0%	-13.9%	-11.8%
February	-6.9%	-14.8%	-11.8%
March	-6.7%	-14.7%	-11.9%
April	-7.7%	-15.8%	-11.4%
May	-8.1%	-16.1%	-11.5%
June	-4.4%	-12.0%	-11.5%
July	-2.4%	-10.2%	-11.1%
August	-3.7%	-11.4%	-11.3%
September	-6.4%	-13.6%	-12.9%
October	-7.5%	-15.6%	-11.5%
November	-7.2%	-15.0%	-12.1%
December	-5.4%	-13.4%	-11.5%

Monthly change in class annual energy consumption

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Energy Use	**0.7%**	**0.7%**	**1.1%**
January	0.5%	0.5%	1.0%
February	-0.5%	-0.5%	0.7%
March	-0.3%	-0.3%	0.7%
April	-1.5%	-1.5%	0.6%
May	-1.9%	-1.9%	0.6%
June	2.2%	2.2%	1.6%
July	3.8%	3.8%	2.0%
August	2.8%	2.8%	1.8%
September	0.6%	0.6%	1.2%
October	-1.2%	-1.2%	0.6%
November	-0.5%	-0.5%	0.7%
December	1.0%	1.0%	1.1%

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