Modeling Customer Response to Xcel Energy's RD-TOU Rate

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PRESENTED TO

Xcel Energy

PRESENTED BY

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Background

The purpose of this presentation is to describe our modeling of likely customer response to Xcel Energy's proposed RD-TOU rate design

The RD-TOU design features a demand charge, in addition to a fixed charge and an energy charge

In prior work on price response, we have used our PRISM modeling suite. The GREEN PRISM was used to analyze the impact of Xcel Energy's inclining block rates (IBR) in 2010. In work for other utilities, we have used the BLUE PRISM to analyze the impact of time-varying rates.

The methodology that we have used to model response to demand charges is an extension of this PRISM modeling framework

We model customer price response using three different approaches to capture the range of ways in which customers might response to a demand charge

Overview of methodology

We model three different ways in which customers could respond to Xcel's proposed rate offering

1) Arc-based approach. Customers are assumed to be aware that electricity costs more during the peak period and less during off-peak hours. The extent to which they shift load from peak hours to off-peak hours is based on the magnitude of the peak-to-off-peak price ratio and its relationship to price response as estimated in more than 40 residential pricing pilots.

2) System-based approach. Like the Arc-based approach, customers are assumed to respond to the new rate as if it were a time-of-use rate. Their response is estimated using a system of two demand equations. This modeling framework has been the basis for estimating peak load reductions in the context of AMI business cases in California, Maryland, Michigan, Florida, and Connecticut.

3) Pilot-based approach. Peak demand reductions are based directly on the average results of three residential demand charge pilots. These are the only three pilots that have quantified residential customer response specifically to demand rates. One of the pilots found specifically that customers respond similarly to demand charges and equivalent TOU rates.

In all three of these approaches, we account not only for the load shifting that will occur due to the new rate design, but also for a change in total consumption that is likely to occur as individual customers' average rates increase or decrease as a result of the new rate design.

Overview of methodology (cont'd)

Current Schedule R

	Charge
Service & facility charge ($/month)	6.75
Non-ECA riders ($/kWh)	0.012
ECA rider ($/kWh)	0.031
Energy - first 500 kWh ($/kWh)	0.046
Energy - 500+ kWh ($/kWh)	0.090

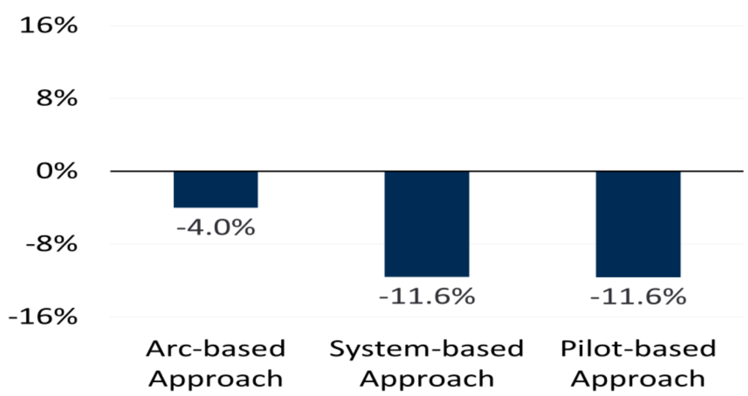
Proposed Schedule RD-TOU

	Charge
Service & facility charge ($/month)	9.53
Grid use ($/month)	14.56
Non-ECA riders ($/kW)	3.78
ECA rider - peak ($/kWh)	0.036
ECA rider - off-peak ($/kWh)	0.028
Energy ($/kWh)	0.005
Demand ($/kW)	7.88

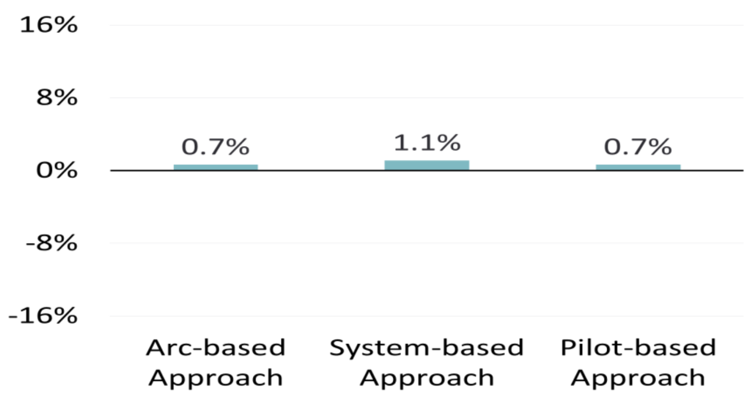
- For each of 200+ customers from Xcel Energy's load research sample, we compare the current Schedule R to the proposed Schedule RD-TOU on a monthly basis for calendar year 2013
- This allows for a comparison of today's two-part rate to a three-part rate that would be enabled by Xcel Energy's grid modernization proposal
- In the analysis, the charges in Schedule RD-TOU are modified to make the rate revenue neutral to the current Schedule R rate for the load research sample (those changes are not reflected in the tables above)

Overview of results

Change in Avg Peak Period Demand (Summer)



Change in Annual Electricity Consumption



Comments

- The results of all three approaches are relatively consistent
- Average peak demand reductions during summer months range from 4.0% to 11.6% across all customers
- Average annual energy consumption increases slightly; this is driven by a number of factors, including (1) that the average price of electricity decreases for most hours of the year for all customers and (2) the average daily rate decreases for large customers

Conclusions and recommendations

There is a substantial amount of empirical, theoretical, and intuitive support for the notion that customers will reduce peak demand with the introduction of a demand charge.

At the same time, the revenue neutral nature of the rate change means impacts on total electricity consumption are likely to be modest. Some customers will reduce total consumption in response to an average price increase and vice versa, but overall these are largely offsetting effects.

We recommend using the results of the System-based approach as a starting point for estimating system-level benefits of the new rate design. This is an internally-consistent modeling framework that has been adopted by regulatory commissions in other jurisdictions in the context of assessing the benefits and costs of grid modernization.

Methodology Detail

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%

* The timing of the peak period for measuring the demand charge billing determinant is different than the timing of the peak period in the ECA rider. In this example, we have shown the peak period of the demand charge. The peak/off-peak split for the ECA rider is 350 kWh/month (peak) and 420 kWh/month (off-peak)

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

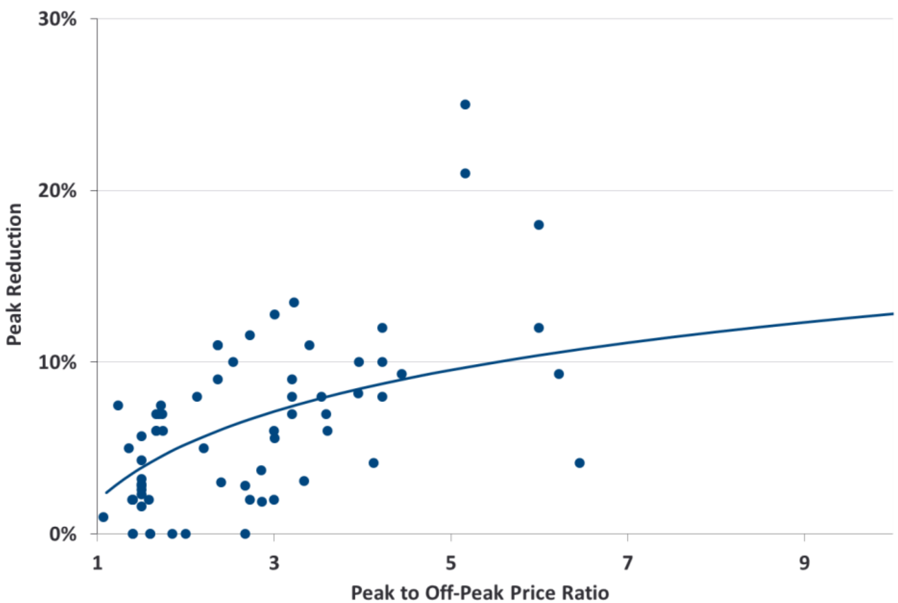
All-in Price	Peak	Off-Peak
Service & facility charge ($/kWh)	0.0130	0.0130
Grid use ($/kWh)	0.0199	0.0199
Non-ECA riders ($/kWh)	0.1518	0
ECA rider ($/kWh)	0.0357	0.0319
Energy ($/kWh)	0.0046	0.0046
Demand ($/kWh)	0.3165	0
Total ($/kWh)	**0.5415**	**0.0694**
All-in peak-to-off peak price ratio	**7.8**	

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

TOU Impacts Observed in Pricing Pilots



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.

Comments

- 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)

Accounting for a Change in Average Price

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

	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
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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.

Comments

- 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

Illustration of System-based Approach

Model Inputs	Basic Drivers of Impacts	Load Shape Effects	Aggregate Load Shape and Energy Consumption Impact
Customer's peak period usage; Customer's off-peak period usage	Peak-to-off-peak usage ratio	Substitution effect (i.e. load shifting)	Overall change in load shape (peak and off-peak by day)
All-in peak price of new rate; All-in off-peak price of new rate	Peak-to-off-peak price ratio		
Central air-conditioning saturation; Weather; Geographic location; Enabling technology (e.g. PCT or IHD)	Elasticity of substitution; Daily price elasticity		
Load-wtd avg daily all-in price of new rate; Existing flat rate	Difference between new rate (daily average) and existing flat rate	Daily effect (i.e. conservation or load building)	

Comments

- 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

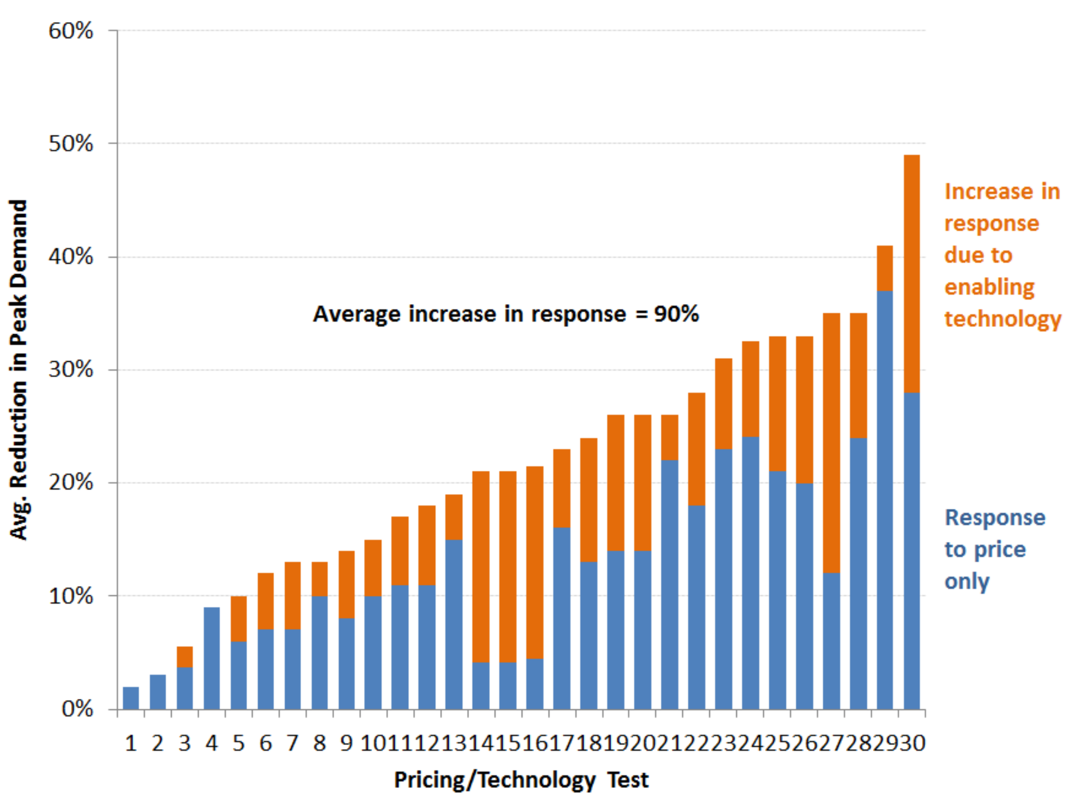
- The energy charge in the RD-TOU rate is adjusted to make up any remaining difference in revenue collected from the current rate and the proposed rate

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

Price Response with and without Technology



Comments

- 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

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%