The Top 10 Questions about Demand Charges

PRESENTED TO

EUCI Residential Demand Charges Symposium

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The top ten questions about residential demand charges

- **10. Why offer a demand charge?**
- 9. What do we know about existing demand rates?
- 8. How will customer bills be affected?
- 7. How should a demand charge be designed?
- 6. Is a demand charge a fixed charge?
- 5. Can customers understand demand charges?
- 4. Will customers respond to a demand charge?
- 3. How will utility revenues be affected?
- 2. What will be the role of enabling technology?
- 1. When is the right time to introduce a demand charge?

10. Why offer a demand charge?

Why offer a demand charge?

Thank you, Ahmad and Cass!

1 down, only 9 to go...

9. What do we know about existing demand rates?

At least 19 U.S. utilities currently offer residential rates with demand charges

Summer Demand Charges in Existing Rates



Comments

- 24 unique rate offerings across
 14 states
- 10 IOUs, 7 municipal utilities, 2 rural electric cooperatives

Observations about existing demand rates

Mostly offered on opt-in basis, sometimes mandatory for sub-classes

Emerging trend toward new rollouts and enhanced marketing

Low enrollment but not necessarily due to lack of interest

Typical enrollee at least 2x size of average customer

There is no one-size-fits-all approach across the 19 offerings

- 10 vary by season
- 8 combined with time-varying energy charge
- 6 measure demand during peak period
- 2 measure demand over a 60 minute interval

Observations about existing demand rates (cont'd)

Reasons for offering the rates have changed

- Older rates: Improve load factor (opt-in)
- Newer rates: More equitable cost recovery (opt-in)
- Future rates: Equity and fairness, (opt-out or mandatory)

Rates typically recover distribution and generation capacity costs and sometimes transmission, but with a price cap

Little empirical assessment of the rates' impacts has been conducted

8. How will customer bills be affected?

The rate change will affect each customer's bill differently

Distribution of Bill Changes



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Bill impacts will depend on the rate's design

Distribution of Bill Changes for Revenue Neutral Rates



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7. How should a demand charge be designed?

Designing a demand charge is a complex endeavor requiring careful consideration of many key factors

Decision	Options	Considerations
How to define demand	 System coincident peak Class coincident peak Billing demand (max of month) A combination of these 	Is the charge intended to convey system-level capacity costs (e.g., generation capacity), distribution-level costs (e.g. transformers), or some combination?
Time interval of demand measurement	- 15 mins - 1 hour - etc.	Does load diversity necessitate 15-minute measurement? There are tradeoffs between precision and customer acceptance.
Relationship to other charges	- Fixed charge - Time-varying energy charge	Is there overlap in the costs being recovered through each charge type? What is the most effective way to convey price signals to customers?
Applicable customer segment	 Size eligibility constraints Variation by geographic location 	Should the charge vary with the size of a customer? Should it be higher in congested areas of the grid?
Seasonality	- Seasonal differentiation - Year-round - Demand ratchet	What is the relationship between summer and winter demand- related costs? Is demand measured on a monthly or annual basis (or somewhere in between?)
Customer enablement features/requirements	- Demand subscription - Enabling technology	Should the rate be coupled with the provision of demand limiters or other technology? Should customers subscribe in advance to a certain demand level?

Commercial and industrial (C&I) rate provide a welltested model for rate design

Demand charges have been included in C&I rates for decades

However, at least one design element in C&I rates should be re-examined before incorporating into residential rates

The interval of demand measurement in existing residential demand rates is between 15 minutes and 60 minutes

In some cases, it is dictated by constraints of the metering/billing system

But in most cases, it is simply chosen to be consistent with existing demand rates for commercial and industrial customers

Shorter intervals have the advantage of precision but could lead to a significant increase in customer bill volatility; bills could jump unexpectedly

Careful consideration should be given to this assumption

6. Is a demand charge a fixed charge?

(Spoiler: The answer is <u>NO</u>)

Demand charges do not automatically increase bills for small customers

120%

100%

80%

60%

40%

20%

0%

-20%

-40%

0

500

1.000

% Change

With Increased Fixed Charge



Note: The three-part rate includes a monthly fixed charge of \$10, an energy charge of \$0.077/kWh, and a demand charge of \$6/kW. The revenue-neutral two-part rate includes a monthly fixed charge of \$40 and an energy charge of \$0.083/kWh.

Note: The three-part rate includes a monthly fixed charge of \$10, an energy charge of \$0.060/kWh, and a demand charge of \$9/kW. The revenue-neutral two-part rate includes a monthly fixed charge of \$40 and an energy charge of \$0.083/kWh.

Average Monthly Energy Use (kWh)

2,000

2,500

1,500

- Correlation between bill impact and customer size is stronger with increased fixed charge
- Whether small customers are low income customers is another question entirely...

With New Demand Charge

3,000

3,500

Additionally, demand charges...

✓ Are more closely aligned with the costs that they recover

 Provide customers with an opportunity for bill reductions through demand response and energy efficiency

Could lead to improved load factors and reduced resource costs

Can compensate distributed generation for its capacity value

(But demand charges <u>do</u> require smart/interval meters)

5. Can customers understand a demand charge?

Customers don't need to be electricity experts to understand a demand charge

Responding to a demand charge does <u>not</u> require that the customers know exactly when their maximum demand will occur

If customers generally know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs

This simple message should be stressed in customer marketing and outreach initiatives associated with the demand rate

The following example is a hypothetical illustration of the composition of the typical customer's maximum demand (8.5 kW), and the benefits of staggering the use of a few key appliances

Staggering the use of a few key appliances could lead to significant demand reductions

Avg. Demand Over 30-min

Appliance	Avg. Demand (kW)	
Dryer	4.0	7
Oven	2.0	Flexible
Stove	1.0	(7.5 kW)
Hand iron	0.5	
Misc. plug loads	0.2	Inflexible
Lighting	0.3	– Load
Refrigerator	0.5	(1 kW)
Total	8.5]

Comments

- Use of some of the appliances is inflexible (1 kW)
- Use of other appliances could be easily staggered to reduce demand
- Simply delaying use of the dryer until after the oven, stove, and hand iron had been turned off would reduce the customer's maximum demand by 3.5 kW
- This would bring the customer's maximum demand down to 5 kW, a roughly 40% reduction in demand

4. Will customers respond to a demand charge?

Three experiments suggest that customers will respond



Note: The North Carolina pilot 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

We have developed a model to simulate customer response to demand charges

The model is based on a widely accepted methodological framework that captures two key effects

- Load shifting in response to a change in rate structure
- Conservation (or the opposite) in response to a change in average rate level

The model draws on an extensive library of customer price elasticity estimates found in more than 40 pricing pilots over the past decade

Our simulation for a hypothetical demand rate found that the average customer would reduce their max demand by 5%

Residential class peak-coincident demand would drop by 1.7% due to load diversity; demand during system peak would drop by a slightly lower amount

New empirical research would improve our understanding of customer response

There are at least two viable approaches for reliably testing the impact of demand charges

Experimental pilot

- Scientific approach designed to provide statistically robust estimates
- Randomly selected treatment and control group to avoid bias
- Pre- and post-treatment data collection

"Test and learn" deployment

- Rates are deployed full scale and modified regularly to assess impacts
- "Before and after" data can still be collected
- A quasi-control group can be created from non-participants
- Less scientific, but facilitates faster deployment

3. What is the role of enabling technology?

Technology will help customers manage demand

Smarter demand management will be enabled by new technologies



And third parties will compete to be the customer's energy advisor



Bill savings could increase significantly with technology



2. How will utility revenues be affected?

Demand charges would reduce a hidden subsidy for customers with distributed generation

Rate Increase due to Rooftop Solar Adoption



Comments

- This is a highly stylized example that should be refined through utilityspecific analysis
- Rate impacts do reflect avoided energy and capacity costs
- Rate impacts do not reflect additional costs associated with net metering such as interconnection costs, billing administration, etc.

But there is a revenue loss risk associated with any voluntary rate offering...

In one analysis, if all customers switch to the demand rate when beneficial, residential revenue would drop by 5%

Accounting for realistic rate switching behavior, revenue loss would be more like 3%

One approach to mitigating the revenue impact has been to build the anticipated revenue loss into the new rate design

Another approach is to recover the lost revenue from the customers who are on the old flat rate

1. When is the right time to introduce a demand charge?

The transition to a demand charge will take time and require careful planning

Rate Design	Pilots	Impact Analysis	Transition Plans	Regulatory Activity
Rate benchmarking	Pilot design	Load impacts	Multi-year rate rollout	Rate case testimony
	Sample	Bill impacts	strategies	·
Cost structure	selection	_		Stakeholder
review	Drococc	Revenue	Protections for	outreach and
Formation of	evaluation	impacts	vulnerable customers	education
ratemaking		Conservation		Conferences,
objectives	Customer	impacts	Customer	whitepapers,
	satisfaction		education	webinars, etc.
Rate development	surveys	Societal costs & benefits		
	Load impact			
	analysis			

For more information...

The Electricity Journal



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In an environment of declining sales growth and rising costs, electric utilities and their stakeholders are exploring new mate designs that will better reflect costs while preventing inequitable bill increases for many customers. Residential demand charges have emerged as an attractive option. This article explores the benefits and challenges of introducing a demand charge into retail mates for residential customers.

Ryan Hledik

I. Introduction

The U.S. electricity industry is rapidly changing. Among the biggest challenges facing the industry is a slowdown in sales growth¹ This trend is seen clearly among individual U.S. households. Despite decades of consistent growth in per-capita electricity consumption, data from the U.S. Energy Information Administration (EIA) suggests that we will see a consistent annual decrease over the next decade, as illustrated in Figure 1 This is driven in part by the lingering effects of the Great Recession of 2008–2009, but also by a number of structural factors such as aggressive energy efficiency standards, new demand side management (DSM) programs, and a growing trend in consumer preferences for more energy efficient products.²

At the same time that sales are declining, the cost of maintaining a reliable grid is rising. For example, Northeast Utilities will invest \$43 billion over the next five years to upgrade its

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Presenter Information

Ryan Hledik is a Principal in The Brattle Group's San Francisco office. Mr. Hledik specializes in the economics of policies and technologies that are focused on the energy consumer. He assists clients confronting complex issues related to the recent slowdown in electricity sales growth and the evolution of utility customers from passive consumers to active managers of their energy needs.

Mr. Hledik has supported utilities, policymakers, law firms, technology firms, research organizations, and wholesale market operators in matters related to retail rate design, energy efficiency, demand response, distributed generation, and smart grid investments. He has worked with more than 50 clients across 30 states and seven countries.

A frequent presenter on the benefits of smarter energy management, Mr. Hledik has spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam. He regularly publishes articles on complex retail electricity issues.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.

About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
- Cost of Capital
- Demand Forecasting Methodology
- Demand Response and Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation
- Energy Contract Litigation
- Environmental Compliance
- Fuel and Power Procurement
- Incentive Regulation

- Rate Design and Cost Allocation
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Appendix

Existing Residential Demand Rates

# Utility	Utility Ownership	State	Residential Customers	Effective Date of	Effective Fixed Date of Charge		d Demand Charge ge (\$/kW-month)		iming of demand Demand measurement interval		Peak Hours		Applicable Residential
			Served	Rate		Summer	Winter			Summer	Winter	TOU?	Segment
1 Alabama Power	Investor Owned	AL	1,241,998	7/14/2011	14.50	1.50	1.50	Any time	15 min	NA	NA	Yes	All
2 Alaska Electric Light & Power	Investor Owned	AK	13,968	12/7/1990	11.49	11.11	6.72	Any time	15 min	NA	NA	No	All
3 Arizona Public Service	Investor Owned	AZ	1,019,292	7/1/2012	16.68	13.50	9.30	Peak Coincident	60 min	12:00 - 19:00	12:00 - 19:00	Yes	All
4 Black Hills	Investor Owned	SD	54,617	4/1/2010	12.25	7.61	7.61	Any time	15 min	NA	NA	No	All
5 Black Hills	Investor Owned	WY	2,153	6/1/2010	12.25	6.75	6.75	Any time	15 min	NA	NA	No	All
6 City of Fort Collins Utilities	Municipal	CO	60,464	1/1/2015	5.37	2.40	2.40	Any time	15 min	NA	NA	No	All
7 City of Kinston	Municipal	NC	9,776	7/1/2014	14.94	10.05	7.81	Peak Coincident	15 min	13:00 - 19:00	7:00 - 9:00 &	Yes	All
8 City of Longmont	Municipal	CO	34,697	1/1/2014	15.40	5.75	5.75	Any time	15 min	NA	14.00 - 20.00 NA	No	All
9 Dakota Electric Association	Cooperative	MN	94,924	9/11/2014	11.00	12.90	9.30	Any time	15 min	NA	NA	No	All
10 Dominion	Investor Owned	NC	101,158	11/1/2012	12.00	8.55	5.00	Peak Coincident	30 min	13:00 - 21:00	6:30 - 12:00	Yes	All
11 Dominion	Investor Owned	VA	2,105,500	1/25/2014	12.00	5.68	3.95	Peak Coincident	30 min	11:00 - 22:00	7:00 - 11:00	Yes	All
12 Duke Energy Carolinas, LLC	Investor Owned	NC	1,608,151	11/1/2013	13.83	8.03	4.01	Peak Coincident	30 min	12:00 - 19:00	7:00 - 12:00	Yes	All
13 Duke Energy Carolinas, LLC	Investor Owned	SC	460,178	10/1/2013	13.83	7.92	3.98	Peak Coincident	30 min	13:00 - 19:00	7:00 - 12:00	Yes	All
14 Fort Morgan	Municipal	CO	5,273	2/1/2015	6.13	10.22	10.22	Any time	15 min	NA	NA	No	All
15 Georgia Power	Investor Owned	GA	2,072,622	1/1/2015	11.00	6.42	6.42	Any time	30 min	NA	NA	Yes	All
16 Midwest Energy Inc	Cooperative	KS	29,951	7/1/2014	22.00	6.40	6.40	Any time	15 min	NA	NA	No	All
17 Otter Tail Power Company	Investor Owned	MN	47,699	10/1/2011	16.00	6.08	5.11	Any time	60 min	NA	NA	No	All
18 Otter Tail Power Company	Investor Owned	ND	44,910	12/1/2009	16.00	6.52	2.63	Any time	60 min	NA	NA	No	All
19 Otter Tail Power Company	Investor Owned	SD	8,648	6/1/2011	16.00	7.05	5.93	Any time	60 min	NA	NA	No	All
20 Salt River Project	Political Subdivision	AZ	891,668	1/4/2015	32.44 -	9.59 or 17.82	3.55 or	Peak Coincident	30 min	13:00 - 20:00	17:00 - 21:00	Yes	DG only
					45.44	or 34.19	5.68 or						
21 South Carolina Public Service Authority	State	SC	140,126	12/1/2013	24.00	11.34 or 4.85	11.34 or	Peak Coincident	30 min	13:00 - 19:00	6:00 - 10:00	No	All
22 Swanton Village Electric Department	Municipal	VT	3,208	4/16/2013	25.05	6.38	6.38	Any time	15 min	NA	NA	No	All
23 Westar Energy	Investor Owned	KS	323,581	Proposed	15.00	10.00	3.00	Any time	30 min	NA	NA	No	All
24 Xcel Energy (PSCo)	Investor Owned	CO	1,182,093	10/30/2009	40.00	4.84	4.84	Any time	15 min	NA	NA	Yes	All

Notes:

Peak periods are applicable from Monday through Friday excluding following holidays : New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas.

4-5: Blacks Hills also offers an optional time-of-use rate for customers owning demand controllers; the rate can be combined with a demand charge that is measured during the peak period.

7: Between May and September peak hours are from 13:00 to 19:00. For October and April peak hours are from 7:00 to 9:00 and 14:00 to 20:00. Between November to March peak hours are from 7:00 to 9:00.

9: This rate is available to residential customers with at least 5 kW of controlled electric heating units. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve months. 17-19: Otter Tail Power Company determines demand based on the peak one-hour reading recorded during the winter period for the most recent 12 months.

20: This rate schedule is only for residential customers that have a solar DG connection. The demand charge is tiered and applies to demand with thresholds of the first 3 kW, the next 7kW, and all remaining kW.

21: South Carolina Public Service Authority has two demand charges based on time-of-use. The peak demand charge is \$11.34/kW and the off-peak demand charge is \$4.85/kW.

23: Westar Energy's rate has been proposed by the utility in an ongoing regulatory proceeding but has not yet been approved.