Minnesota Power
Time of Day Rate Design Recommendations
Summary of Stakeholder Meetings

February 14, 2019

Process facilitated by the Great Plains Institute and Center for Energy and Environment

Questions about this summary should be directed to:

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I. Introduction

Time-varying rates, in which the price of electricity varies across the time of day and possibly throughout the year, have been adopted by many utilities for decades. Increasingly, these rates are being deployed as one of many strategies to address profound changes affecting the electric system, including advances in technology, an increasing desire for more customer choice, and pressure to reduce carbon emissions.

Time-varying rates touch on all of these changes and can have a number of benefits. New metering and communications technology makes it possible to much more accurately measure how much electricity a customer used during specific times of the day and bill those times at different prices. Customers who can respond to a time-varying rate by shifting some of their electricity usage from a high-cost time of day to a low-cost one can benefit by reducing their electric bills. If many customers respond in this way, a time-varying rate can reduce the need for fossil fuel-powered electricity generation during high-usage times and better utilize renewable electricity such as wind power during low-usage ones. Reducing or shifting peak load in this way can make the entire system more reliable and cost-effective, saving money even for customers who don't participate.

While the concept of a time-varying rate makes sense for many reasons in theory, the details matter. Each electric utility has a different load profile based on its customer base and a different generation mix based on its resources and participation in a regional market. These differences require each rate to be tailored to its unique situation.

This document summarizes the results of a stakeholder engagement process to solicit input on time-varying rate recommendations for Minnesota Power, in compliance with an order from the Minnesota Public Utilities Commission in Docket No. E015/M-12-233 to develop such recommendations following the review of a time-varying rate pilot that concluded in the fall of 2018.

II. Background

Since October 2014, Minnesota Power has operated a residential time-of-day (TOD) rate pilot, which included an on-peak period, an off-peak period, and a critical peak pricing (CPP) component. At its August 19th, 2018 meeting, the Minnesota Public Utilities Commission (Commission) approved Minnesota Power's request to end formal evaluation of the pilot program and asked the utility to file, by February 1, 2019, a set of recommendations for a new TOD rate design. The Commission also required Minnesota Power to conduct stakeholder engagement to inform the development of these recommendations.

In August 2018, Minnesota Power hired the Great Plains Institute (GPI) and the Center for Energy and Environment (CEE), co-conveners of the e21 Initiative, to design and conduct a stakeholder engagement process to solicit input on future TOD rate design recommendations. GPI and CEE worked with Minnesota Power to engage stakeholders across four meetings from September 2018 to January 2019. Minnesota Power also hired Navigant as a third-party technical expert to assist with developing rate design options. Staff from Navigant were present, either in-person or by phone, at all four meetings.

This document provides a summary of remarks by stakeholders at those four meetings. The notes do not indicate consensus among the group, but rather are meant to capture the collective discussion and key points raised by participants. No view should be attributed to any specific individual or organization that participated in the process. Importantly, the stakeholder engagement process and this resulting summary are intended to support, but not replace, important discussions within the formal regulatory process.

III. Process Overview

PROCESS OBJECTIVES

Co-facilitators GPI and CEE designed the stakeholder engagement process to achieve the following objectives, with input from Minnesota Power and in consideration of comments submitted in Docket No. E015/M-12-233 and made orally at the MN PUC meeting on August 19, 2018:

1. Better understand the context and parameters for an advanced TOD rate in Minnesota Power Territory, including:
    - Relevant results and conclusions from the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.
    - Status of metering and communications infrastructure, including current deployment of technology and planned timelines and projected costs for future deployment.
    - System load profile, associated costs, and generation mix at different times of day and year.
2. Develop shared objectives and design principles for an advanced TOD rate, building on those developed for Xcel Energy's TOU rate pilot, while recognizing key differences that are unique to Minnesota Power.
3. Identify recommendations for when, how, and at what scale an advanced TOD rate should be implemented (considering metering infrastructure and other factors).
4. Review and provide feedback on advanced TOU rate design options developed by Minnesota Power, using the objectives and design principles as a framework for evaluation.
5. Identify areas of agreement, disagreement, and desires for further inquiry among stakeholders to inform and support the formal regulatory process.

TIMELINE AND MEETING TOPICS:

The objectives listed above were broken down into four meetings that took place from September 2018 to January 2019, each covering the topics listed below. The process also included a break between Meetings 2 and 3 to allow Minnesota Power time to develop draft recommendations to be brought back to the group for review. Meetings were held in person in Minneapolis and Duluth, and by webinar as noted below.

Meeting 1: September 11, 2018 (Duluth, MN)

- Presentation from Minnesota Power and group discussion on current metering and communications infrastructure.
- Development of an initial list of shared objectives and design principles for an advanced residential TOD rate in Minnesota Power's service territory, including recommendations for when, how, and at what scale a TOD rate should be implemented.
- Identification of stakeholder questions pertaining to the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.

Meeting 2: September 28, 2018 (Minneapolis, MN)

- Presentation from Minnesota Power on system load profile, associated costs, and generation mix at different times of day and year.
- Presentation (as needed) from Minnesota Power and discussion on relevant results and conclusions from the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.
- Follow-ups from Minnesota Power with additional information on metering and communications infrastructure as needed.
- Refinement of objectives and design principles in consideration of Minnesota Power's metering infrastructure, load profile, and other factors.

BREAK: October-November 2018

- Minnesota Power developed rate design options and an implementation plan for the group to react to at the next meeting.
- Stakeholders reviewed information developed to date and provided additional thoughts as needed.

Meeting 3: December 10, 2018 (Minneapolis, MN)

- Presentation from Minnesota Power on draft TOD rate design options and implementation plan.
- Discussion of TOD rate design options and any areas of specific interest or concern, using objectives and design principles as a framework for evaluation.

Meeting 4: January 11, 2019 (Virtual Meeting)

- Presentation from Minnesota Power on refined TOD rate design options, responding to initial feedback.
- Identification of remaining areas of agreement, disagreement, and desires for further inquiry among stakeholders to inform and support the formal regulatory process.

STAKEHOLDERS

Together, GPI, CEE, and Minnesota Power developed a list of groups to invite to participate in this process that could offer a diversity of perspectives important to the development of a residential Time of Day rate, including all parties that had commented in Docket No. E015/M-12-233. Representatives from the following groups were invited to participate in this process:

- Citizens Utility Board of Minnesota
- City of Duluth
- Ecolibrium 3
- Energy CENTS Coalition
- Fresh Energy
- Minnesota Citizens Federation -- Northeast
- Minnesota Department of Commerce
- Minnesota Office of the Attorney General

The process benefitted from participation from some, but not all of these invited groups. In general, representatives from Citizens Utility Board, Fresh Energy, Department of Commerce, and the Office of the Attorney General were able to make all or most meetings. The City of Duluth and Ecolibrium 3 were able to attend some meetings. Energy CENTS Coalition and the Citizens Federation were not able to attend any meetings.

IV. Objectives of a TOD Rate

To guide the development of TOD rate recommendations, the group adopted the following two high-level objectives, which are meant to state the minimum benefits that a new TOD should deliver and accordingly, to serve as a threshold for determining whether a TOD rate makes sense compared to other possible strategies to achieve these objectives:

1. **Reduce system costs,** including consideration of peak demand, the need for future investments in the system, and other costs (e.g. market costs).
2. **Increase customer participation and satisfaction,** with participation loosely defined as the number of customers actively reducing their on-peak load, and satisfaction based at least partly on the opportunity to reduce costs.

V. Design Principles

To provide further guidance, the group developed, and iteratively refined over the course of the four meetings, the following nine design principles. The idea of these principles was that if a TOD rate successfully achieved each of these, then the group would likely be able to support it. Importantly, these were meant to be taken as a package (i.e., stakeholders may not have supported each of these principles on their own, but found the full set acceptable. Adherence to a single principle could have unintended consequences without the others providing balance).

Moreover, the principles were sorted into two lists—six "must-have" principles and three "nice-to-have" principles—based on stakeholder input in an online survey. The differentiation between "must-have" and "nice-to-have" was simply meant to provide a sense of priority since the list was long. The principles are listed below, along with commentary that arose during discussions of each principle.

MUST-HAVE DESIGN PRINCIPLES (TO BE TAKEN AS A PACKAGE):

1. Provide an evaluation of the costs and the benefits of the TOD program.

The benefits of a new TOD rate, including reduced system costs and the opportunity to reduce bills through behavior change, should outweigh the costs, including customer education, marketing, and administration. However, participants acknowledged that the benefits may be difficult to measure and that some of the costs of implementing a TOD rate, such as metering, may be shared with other initiatives outside of the rate itself. Moreover, the group understood that a full evaluation of costs and benefits would not be possible until the point of a complete filing for a new rate.

2. Include considerations for indemnifying low-income customers.

Impacts on low-income customers were a common concern throughout stakeholder discussions, though it was not clear whether the bill impacts of proposed TOD rate designs were significant enough to warrant indemnification for low-income customers. Minnesota Power offered to look further into this. Participants stated that at minimum they'd like to see a transition plan that can indemnify initial impacts of a TOD rate on low-income customers, while allowing them the opportunity to save money on bills as a result of behavior change.

Defining low-income customers was also raised as a concern, but not fully addressed in these meetings as the Commission had taken up the issue in other dockets. The concern, which has been raised for other utilities in Minnesota as well, is that low-income customers are often defined based on participation in LIHEAP—a definition that leaves out many customers who are eligible for LIHEAP assistance but not actively participating in the program.

3. Enable energy conservation, cost-effective integration of additional renewables, and reduction of GHG emissions.

Stakeholders agreed that a successful TOD rate should seek to reduce energy usage and greenhouse gas emissions while enabling the cost-effective integration of additional renewable generation. At the conclusion of the four meetings, the group was satisfied that the rate options presented by Minnesota Power would meet this principle. However, several participants agreed that a more forward-looking analysis of system peak, taking into account additional renewable generation expected to come online in future years, would improve the rate design.

4. Provide rates that accurately reflect the cost to serve, both now and looking forward.

Minnesota Power has a very unique load profile, which is relatively flat throughout the year and over the course of a day due to a large industrial load. Residential load, which is the target of potential TOD rate designs, makes up only 10% of gross load. As a result, stakeholders asked Minnesota Power to assess the best approach for linking a TOD rate to costs in a way that would meet this principle while enabling a price differential between time periods that would incent customers to shift usage from on-peak to off-peak periods. In response, the company presented a series of options for cost allocation and associated rate designs. As noted below, the group came to rough consensus on one of these options, which allocated embedded costs to different time periods based on the load that caused those costs.

5. Consider using an opt-out approach for the base TOD rate.

One key decision in designing a time-varying rate is whether to automatically assign customers onto the rate and allow them to "opt-out" if they wish, or to encourage customers to "opt-in." Research has shown that opt-out rate designs tend to be more cost-effective because they have lower marketing costs to achieve high levels of participation. Group members had varying opinions on whether the rate should be opt-out or not. Some participants favored an opt-out design because it would place all customers on a time-varying rate, increasing the rate's impact; others, in keeping with Design Principle 1, wanted Minnesota Power to weigh the costs and benefits of an opt-out approach and determine whether it would be appropriate. For this reason, the group asked Minnesota Power to consider an "opt-out" design but did not require it as part of this principle.

Additionally, the group discussed that Minnesota Power could deploy a base TOD rate with an "opt-out" approach, and then offer additional "opt-in" components, such as critical peak pricing or a peak time rebate that would allow customers additional opportunities to reduce bills in return for shifting loads during times of peak usage.

6. Give customers adequate tools to access and understand their usage data.

While some group members felt this was a "must-have" principle, it wasn't discussed at length in meetings because it applied to a level of detail beyond the scope of the initial rate design options being developed. If and when a new rate offering is fully developed, group members stated that they'd like the offering to provide a strong interface for customers to access usage data, as well as co-marketing of efficiency programs and technologies that can help with responding to a time-varying rate. Additionally, the group noted that the recently completed TOD rate pilot could help inform the most effective approaches to achieve this principle.

NICE-TO-HAVE DESIGN PRINCIPLES:

1. Balance precision and practicality, both for the utility and for customers.

While no group member felt this was a "must have" principle, some participants did state that it's important to set timeframes that are not significantly disruptive to customers. To achieve this, it could be helpful to understand the extent to which customers can and cannot shift load to affect system peak. Since Minnesota Power is a winter-peaking utility in a northern climate, customers with electric space heating were of particular concern.

Additionally, some stakeholders were concerned about how a TOD rate would interact with existing customer programs such as CARE and Budget Billing, while also acknowledging that it's important to include as many customers (or customer types) as possible in a TOD rate offering.

2. Design within the parameters of the revenue requirement.

There was discussion among the group about whether a TOD rate would be revenue-neutral, which would be challenging given that Minnesota Power does not have a decoupled rate structure. For that reason, the group suggested that any TOD rate should be designed within the parameters of the revenue requirement.

3. **Evaluate options to layer products on top of base TOD rate, considering what drives demand at peak (CPP, PTR, BDR).**

Products layered on top of a TOD rate could include incentives or disincentives for reducing load during critical events. These could include “critical peak pricing,” in which electricity prices increase dramatically during critical events, “peak time rebate,” in which customers receive a monetary reward for reducing usage (but are not assessed a penalty if they don’t respond), or “behavioral demand response,” in which customers are given positive, but non-monetary feedback (e.g., via a thank-you message) in return for reducing load during critical events in response to a request from the utility.

The group was open to Minnesota Power exploring these options and did not feel strongly for or against their inclusion. As noted above, the group suggested that additional products could be optional under an “opt-in” program design, even if a TOD rate was set as the standard rate for all residential customers.

VI. Technology and Timing

In the group’s first meeting in September 2018, Minnesota Power staff presented on the current state of the utility’s metering and communications infrastructure, as well as plans for future investments in new technology. One of the key findings from this presentation was that Minnesota Power has deployed Advanced Metering Infrastructure (AMI) meters to roughly half of its residential customers, but it doesn’t currently have a Meter Data Management (MDM) system to collect and process the data produced by those meters. Without an MDM, utility staff have to manually address any billing errors — a laborious process that would make widespread use of AMI meters uneconomical.

Minnesota Power is in the process of acquiring the needed MDM system, but it likely won’t be fully operational until 2022. For this reason, stakeholders thought that a phased approach to deploying a new TOD rate, like the one described below, would make sense. This would allow Minnesota Power to test, learn, and scale a new rate design over time and in accordance with the implementation timeline of the MDM system. Importantly, there was not consensus on a specific phased deployment plan for a TOD rate. The plan described below is just an example of how a phased deployment could be implemented to align with the timeline of the new MDM system:

SAMPLE PHASED DEPLOYMENT PLAN

Phase 1: Before MDM is in place (expected 2019-2020)

- Use this as a planning and preparation period, as the benefits of a TOD rate likely wouldn’t justify the resources needed to manually fix billing errors without an MDM.
- Identify a suitable rate design, then look at how to deploy it.
- Conduct strategic planning around leveraging related programs to maximize the benefit of a TOD rate (e.g., energy efficiency programs).

Phase 2: MDM implementation period (expected 2020-2021: 1-year implementation + 1-year stabilization)

- This time period allows a long "runway" during which Minnesota Power can test (see examples below) and prepare for a broader rollout of a TOD rate.
- Test the new rate with some customers (e.g., current pilot participants and/or EV owners) and do shadow billing for all other customers to identify which customers will need the most help, then develop targeted programs to help those customers.
- Possibly test some specific technology or customer segments (e.g., opt-in for EV owners).

Phase 3: Post-MDM implementation, continued AMI deployment (2022-2025)

- Roll-out the new TOD rate over time to all applicable customers as AMI meters are deployed.

Phase 4: Full AMI deployment with MDM operational (2025+)

- AMI meters and TOD rate are fully deployed to all applicable customers.

Additionally, stakeholders discussed that the following considerations could be addressed in early phases of deployment to ensure a successful full-scale rollout. The group felt that these were important to consider but did not have time to discuss them at length. Moreover, some of these may have already been addressed, in part, by Minnesota Power's now concluded Smart Grid Investment Pilot.

CONSIDERATIONS FOR EARLY PHASES OF DEPLOYMENT:

1. **Identify which practices are effective at shifting customer load**, including the peak to off-peak ratios, duration of peaks, and timing of peaks that will send an adequate price signal to customers while accomplishing other state goals.
2. **Identify what outreach and education methods are most effective for different customer segments** (including who is the best messenger).
3. **Understand ramifications for particular customer segments**, with attention to low-income customers, including how much money customer groups saved or lost, how specific practices increased or decreased customer participation and satisfaction, and to what extent customers had the ability to respond. Identify exclusions/issues with specific customer groups and plan for bringing them into the TOD rate (considering phased deployment).
4. **Understand how a TOU rate might enable demand response** (e.g., through critical peak pricing or critical time of day pricing).
5. **Identify what value is provided by different technology options** (e.g., pre-programmed thermostats).
6. **Understand how other customer interventions can be paired with TOU rates and how this affects cost-effectiveness** (e.g., energy efficiency programs).

VII. Rate Design Options

The order from the Commission required Minnesota Power to develop “alternative rate designs” rather than a fully developed TOD rate. To support a robust stakeholder discussion on this topic, Minnesota Power presented six different rate design options to the group at its third meeting in December 2018. These options reflect the possible combinations of three different ways of allocating costs (in accordance with Design Principle 4) and two different approaches to setting peak periods based on an analysis of Minnesota Power’s load profile.

The group provided in-depth feedback in response to these six initial options, which Minnesota Power took into account to develop and present a refined set of options in Meeting 4. Below, we have summarized the key discussion points during these meetings. A complete listing of all feedback received is included in the notes from the individual meetings, which are attached to this summary.

FEEDBACK IN RESPONSE TO RATE DESIGN OPTIONS:

Overall approach

- Creating multiple rate design options based on varying cost allocation and peak period design decisions was comprehensive and helpful for figuring out the best possible solution given Minnesota Power’s unique load profile.
- The general design (though varying depending on the specific option) seemed simple and likely to benefit most customers.

Cost allocation

- Among the three cost allocation options presented in Meeting 3, stakeholders said they preferred “Option A,” which allocated embedded costs across time periods based on the load that caused those costs. After Meeting 3, all refined options that were presented in Meeting 4 were based on this cost allocation method.

Peak period design and impact on pricing

- Three TOD periods (peak, off-peak, and super off-peak) appeared to enable a better customer response compared to the two-period (plus critical peak pricing) design of the recently concluded TOD pilot rate.
- Pricing for the three periods seemed justified based on underlying costs, in accordance with Design Principle 4. However, there was concern among stakeholders that the price difference between on-peak and off-peak periods was not enough to elicit a strong response from customers. Some stakeholders were interested in seeing how slight differences in the peak period design (e.g., increase or decrease the peak period by an hour, change the allocation of the peak period across months of the year, or both) would impact pricing levels to achieve a bigger differential between the peak and super off-peak periods. Minnesota Power made these changes after Meeting 3 and presented them for feedback in Meeting 4, at which point

stakeholders said they preferred the three following options, with some preferring one over the other, but all saying they could probably support one of these three if the benefits were found to outweigh the costs:

- A four-hour peak that is in place year-round but shifts two hours earlier in the day during the summer months to better accommodate the summer peak.
- A five-hour peak that is consistent throughout the year.
- A four-hour peak that only occurs during the summer and winter (i.e., there would be no peak period, leaving only two periods—super off-peak and off-peak period —in April–June and September–October).

Analysis of future generation mix and load profile

- Since the analysis of Minnesota Power's load profile was based on their last resource plan, some stakeholders said they would like to have seen a more forward-looking analysis (e.g., forecasting to 2030) that would consider additional renewable energy generation expected to come online in future years. Participants were specifically interested in whether this might increase the differential between on-peak and off-peak pricing, making the price signals stronger and thereby eliciting a better response from customers.
- Some participants also thought a more forward-looking analysis would make the TOD rate design more accurate at the time of deployment, given the need to wait until the MDM system is fully operational.

Inclusions/exclusions

- There were several questions about whether and how specific customer types might be included in or excluded from this rate. These were not fully resolved in meetings and would need to be addressed in the process of developing a complete rate design offering. The following customer groups were specifically discussed:
    - Electric space heating customers—Minnesota Power is a winter peaking utility, with the peak caused primarily by both primary and supplemental electric space heating, as well as low penetration of air conditioning (which keeps the summer peak lower than other utilities, creating a winter peak). The group noted that this would be important to consider in designing a future TOD rate. Notably, Minnesota Power already has a dual fuel rate that is interruptible in the case of a peak event, which may help inform whether and how to include these customers.
    - Net metering customers—while including net metering customers in a time-varying rates presents some billing challenges, some stakeholders expressed the expectation that these customers should be included, especially if the utility is proposing investment and cost recovery in new metering and an MDM system to help with accurate billing. Minnesota Power estimated that there are currently about 200

customers on a net metering rate and offered to look into how metering and billing could work for these customers under a TOD rate.

- Multi-family building tenants—some stakeholders wanted to know how a TOD rate would apply to customers in multi-family buildings where there are multiple tenants on a single meter.

Effect on Inverted Block Rate

- Minnesota Power currently has an inverted block rate (IBR) for residential customers, in which customers with higher usage pay a higher rate. Multiple stakeholders were interested to know how a TOD rate would impact the existing IBR, including whether the IBR would discontinue in favor of a new TOD rate, if one is developed and deployed. However, there was disagreement on this. Some thought a TOD rate was more favorable because it could integrate additional renewables, support beneficial electrification, and be paired with more effective ways of incentivizing energy conservation (one of the primary goals of an IBR). Others thought that switching from an IBR to a TOD rate could potentially be more costly for the same general benefits, or have adverse impacts on low-usage customers who are currently benefitting from the IBR. Evaluating the impacts of the IBR, including customer benefits, in the process of weighing costs and benefits for a potential TOD rate will help to address this.
- Participants were also particularly interested in how the shift from IBR to a new TOD rate would affect low-income customers.
- One stakeholder commented that if the customer benefit between the IBR and TOD are roughly even, then more consideration should be given to outreach and roll-out of the TOD to ensure smooth implementation so that the benefits can be realized cost-effectively. In other words, effective implementation will be required to enable the benefits of switching from IBR to TOD.

Customer impacts and engagement

- At least one participant thought it would be helpful for Minnesota Power to develop “user profiles” representing different customer types to illustrate how, under each rate design option, customers would be impacted. As noted under Design Principle 2, low-income customers were of significant interest to multiple stakeholders.
- Given the potential for a TOD rate design in which the peak period changes throughout the year, some participants were concerned about the ability of customers to understand the rate design. However, Minnesota Power staff noted that the recently concluded pilot TOD rate was quite complicated, including a critical peak pricing component, and customers showed a strong understanding of the rate in surveys. In response, stakeholders seemed satisfied that Minnesota Power could appropriately educate customers but were still interested in evaluating an education and engagement plan when a new TOD rate is fully developed.

Weighing benefits and costs

- At the conclusion of Meeting 4, multiple stakeholders remarked that they were appreciative of Minnesota Power's genuine attempts to develop TOD rate design options in response to stakeholder input. All participants said that they could probably support one of the three options described above, but would need more information to make a final determination.

VIII. Conclusion

Overall, participants in this process were appreciative of Minnesota Power's genuine efforts to collaborate with stakeholders in the development of new TOD rate design options. Over the course of four meetings, the group came to better understand Minnesota Power's load profile, metering and communications infrastructure, and experience from the recently concluded TOD rate pilot. It became clear that if a future TOD rate is deployed, the timing will need to align with the deployment of a new Meter Data Management system that is expected to be fully operational by 2022. Given this timing constraint, a phased approach to rolling out a new TOD rate may make the most sense.

To support the development of any new TOD rate design, stakeholders developed high-level objectives and a set of more detailed design principles, which Minnesota Power used to develop a series of analysis-based rate design options for the group to review. While stakeholders thought that there were at least three resulting rate design options that could potentially meet the group's objectives and design principles, there was significant interest in evaluating the specific details of any proposed TOD rate to assess costs and benefits. Importantly, the two "Objectives of a TOD Rate" that the group agreed to—reducing system costs and increasing customer participation and satisfaction—can provide a useful rule of thumb for evaluating a new TOD rate, both independently and against other possible options to achieve those same objectives. Moreover, the "must-have" and "nice-to-have" design principles can provide guidance for the development of a new, fully developed TOD rate if doing so is found to be advantageous.

GPI and CEE thank the stakeholders who provided input for their time and effort throughout this process.

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Minnesota Power Advanced Time-of-Day Rate
Meeting 1: September 11th, 2018

Great Lakes Aquarium
353 Harbor Dr, Duluth, MN 55802

1:00pm – 4:00pm

Remote Access Link: https://betterenergy.zoom.us/j/799394140
Dial: +1 646 876 9923 or +1 669 900 6833
Meeting ID: 799 394 140

Agenda

1:00-1:10pm	Welcome, Intro's, Process Overview
1:10-1:20pm	Brief Context for Time-Varying Rates (Lon Huber, Navigant)
1:20-2:00pm	Shared Objectives and Design Principles- Part 1 (For TOD rate itself)
2:00- 2:45pm	Current Metering and Communications Infrastructure (Minnesota Power Staff)
2:45-3:00pm	BREAK
3:00-3:30pm	Shared Objectives and Design Principles- Part 2 (For rollout of TOD rate – when, how, at what scale)
3:30-3:50pm	Identifying Key Questions
3:50-4:00pm	Reflection, Wrap-up, and Next Steps
4:00pm	ADJOURN

TIME VARYING RATES FOR RESIDENTIAL CUSTOMERS

A BRIEF PRIMER

SEPTEMBER 2018

Lon Huber
Director

NAVIGANT

NAVIGANT'S GLOBAL ENERGY PRACTICE

We collaborate with clients to help them thrive in a rapidly changing environment.

CLIENTS

- ✓ 50 largest electric and gas utilities
- ✓ International, federal, and state governments
- ✓ 20 largest independent power generators and gas distribution and pipeline companies
- ✓ Leading oil & gas companies
- ✓ Multiple new energy market entrants and investors

TEAM

- ✓ Industry's largest energy management consulting team
- ✓ Consultants average 15 years of experience
- ✓ 60% have an advanced degree
- ✓ Over 50% have an engineering degree

NAME

- ✓ Among Top 10 in Vault's 2017 Best Consulting Firms for Energy
- ✓ Named "Best Advisory – Renewable Energy" in 9th and 10th Annual Environmental Finance and Carbon Finance Market Surveys

RESIDENTIAL TOU RATES TODAY

- 14% of all US utilities offer a residential TOU; roughly half of IOUs offer one
- Where TOU is available, around 3% of customers are enrolled on average
- 74% of TOU rates have only two pricing periods
- 71% of TOU rates have a price ratio of at least 2-to-1
  - Half of TOU rates have a price differential of at least 10 cents/kWh
- Of the utilities offering TOU rates, roughly half offer more than one TOU option

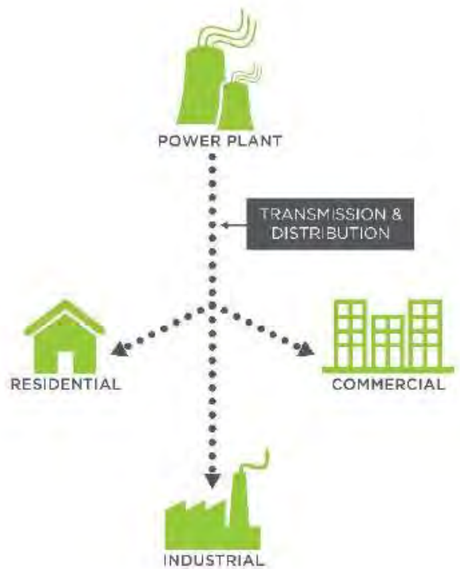
Source: The National Landscape of Residential TOU Rates – Brattle Nov 2017

Attachment A

ENERGY TRANSITION: *TRENDING TOWARD A CLEAN, DECENTRALIZED, INTELLIGENT & MOBILE GRID*

PAST: Traditional Power Grid
Central, One-Way Power System

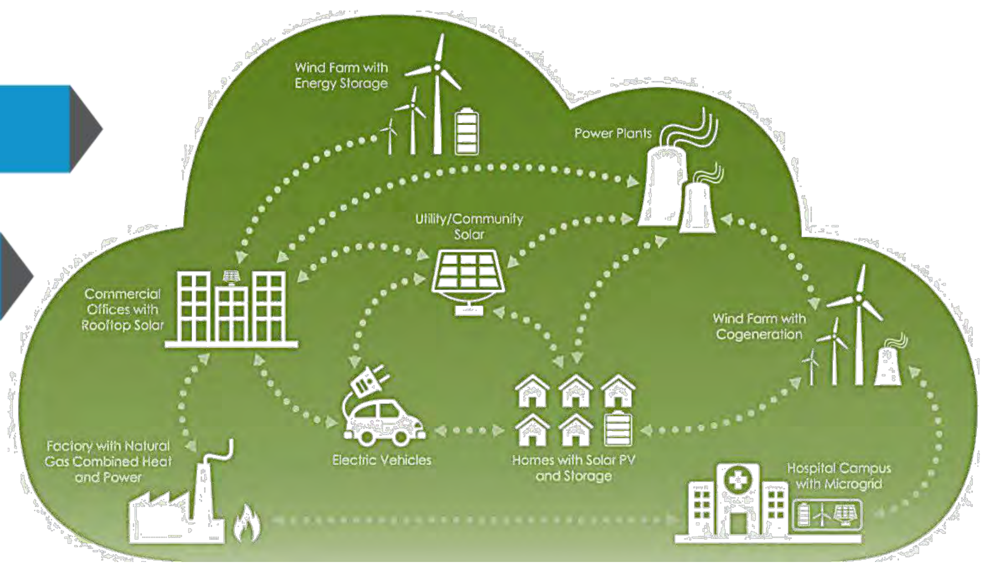
TODAY: The Energy Cloud
Distributed, Cleaner, Two-Way Power Flows



Market Demand

Technology Innovation

Policy & Regulation



2025

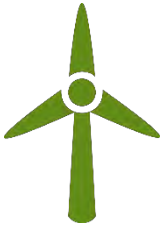
- 746 GW wind[1]
- 668 GW distributed solar
- 144 GW distributed DR
- 62 GW distributed energy storage
- 3.5 GW C&I microgrid capacity
- 22.3m EVs battery-powered
- >5 billion residential IoT

Source: Navigant 2017

NAVIGANT

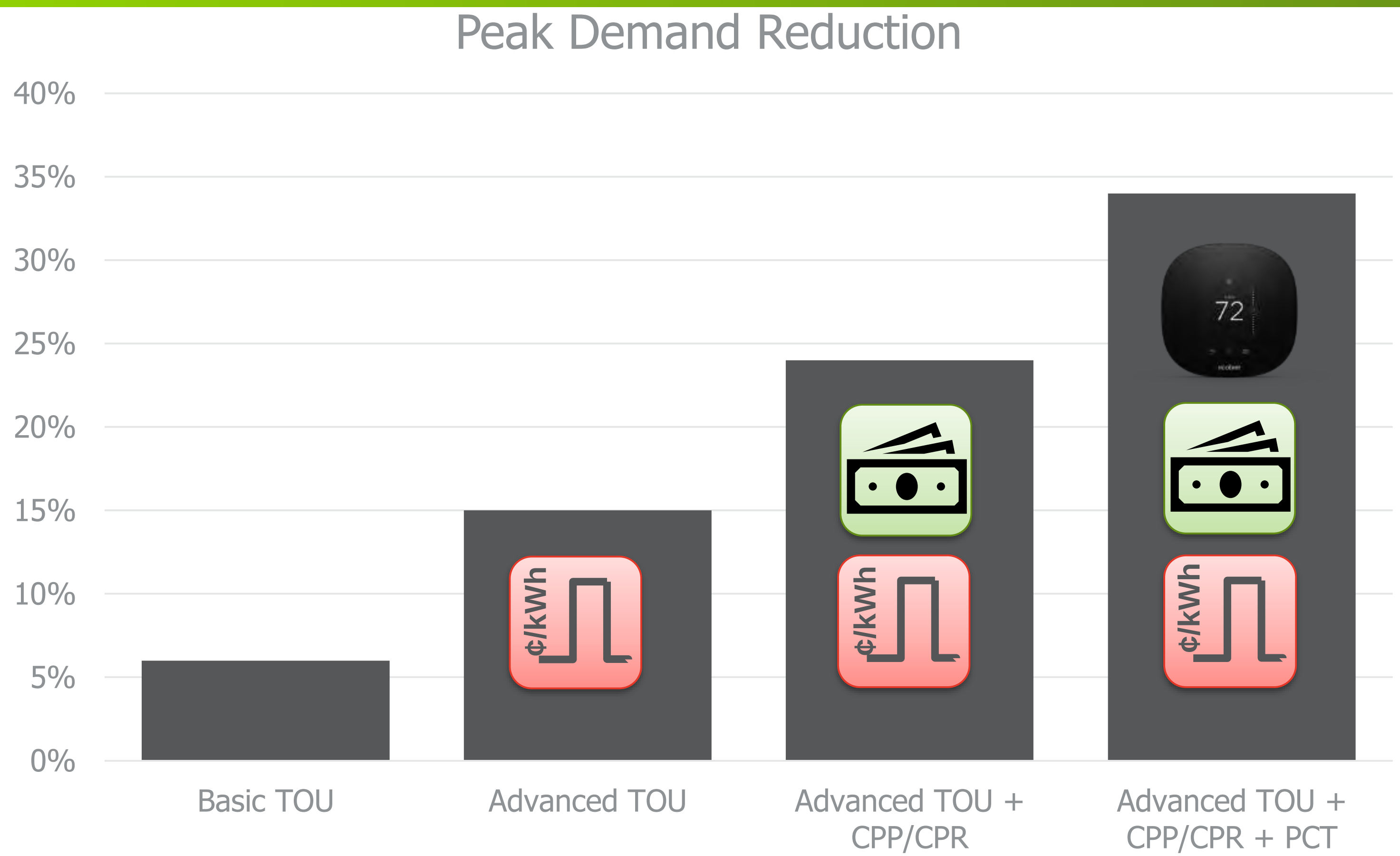
RESIDENTIAL TOU RATES TOMORROW

1. Three or more time periods
2. A focus on capacity rather than energy
3. Shorter time windows from the traditional 10+ hour peak windows
4. Link to low marginal cost hours
5. Better enrollment methods



NAVIGANT

DEMAND REDUCTION POTENTIAL



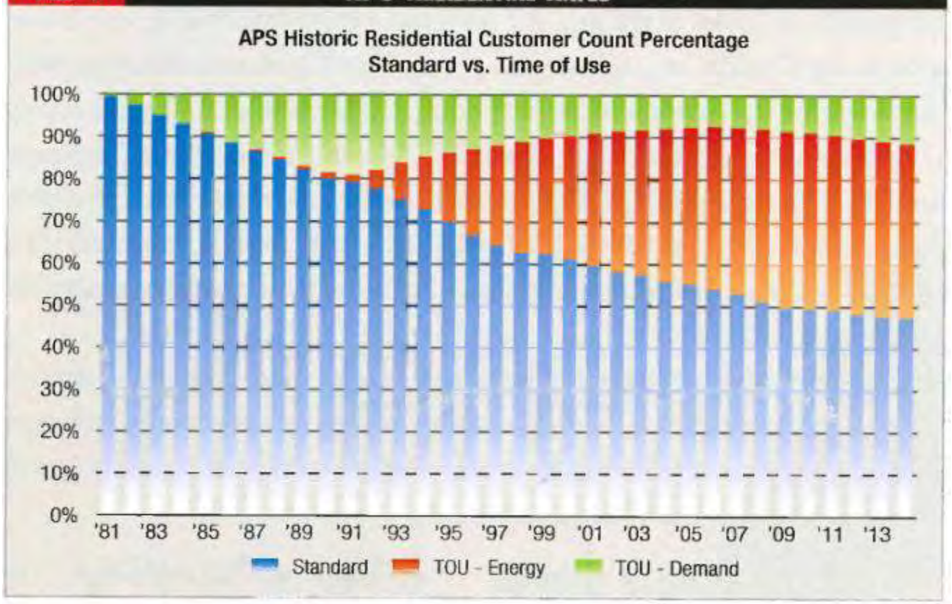
The goal is to turn passive customers into active customers

Source: Strategen and U.S. DOE, November 2016, Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, https://www.smartgrid.gov/document/CBS_Results_Time_Based_Rate_Studies.html

CUSTOMERS ARE HAPPY WITH TIME VARYING RATES OVER THE LONG RUN

- Began offering Time of Use rates in 1982
- Well marketed and advertised
- 568,500 residential customers on time differentiated rates
- ~50% opt-in Time of Use rates

FIG. 1 APS RESIDENTIAL RATES



Source: Strategen/Xcel and APS 2015 Demand Side Management Annual Progress Report
There and Back Again, Fortnightly November 2015

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AMI System Deployment and Future Technology for Time of Day

Daniel Gunderson, P.E.
Distribution Engineering & Operations

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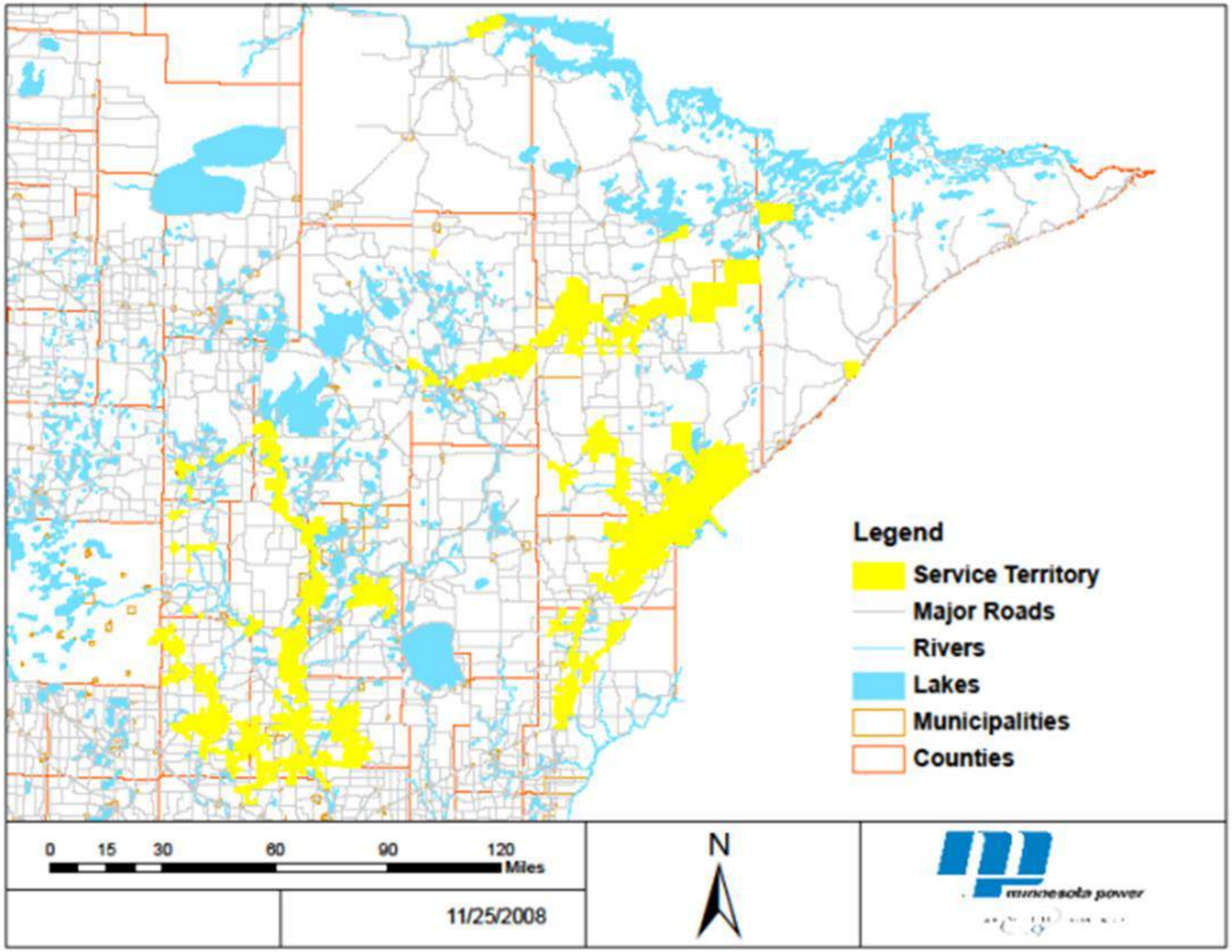
Overview

- Minnesota Power Info
- AMI System Architecture & Overview – Sensus FlexNet
- Current Deployment of the System
- Current Time of Day Pilot Program
- Technology Roadmap

Attachment A

Minnesota Power Service Territory

- Customers: 144,000
- Peak Load: 1970MW
- Distribution: 6200 Feeder Miles
- Transmission: 2500 Line Miles



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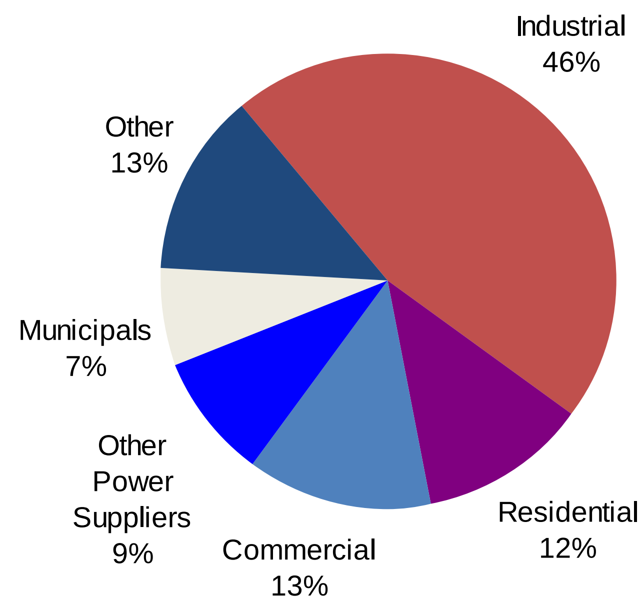
At a Glance

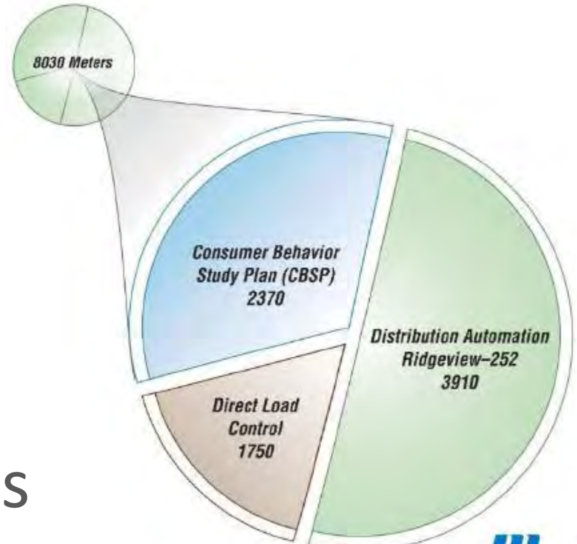
- Large industrial customer class
- Generation and purchased power of 1900 MW
- Service territory includes some of the world's largest known reserves of taconite, copper-nickel, and other precious metals



Regulated Utility Revenue
(6/30/12)

DOE Smart Grid Investment Grant

- Project Dates – May 2010 – December 2014
- Time of Day Pilot through September 2015 (still going)
- Total Project Budget – $3,088,000
- 12/31/2014 - ~$3.5M Actuals
- 100% Deployment Completion
- Meters Deployed: 8030 of 8030
- Review of Four Major Project Areas
    - Dual Fuel – Load Control Upgrade
    - Outage Management System and Distribution Automation (OMS & DA) Smart Feeders Project
    - Meter Data Warehouse
    - Consumer Behavior Study & Critical Peak Pricing Project (TOD)



System Selection

- System Selection was done by AMI/CPP Team
- Analyzed 15 different Vendor Products for AMI System
- Power Line Carrier (PLC), Mesh & Mesh Hybrid Networks, Tower Technologies were all part of the Analysis
- Sensus FlexNet was selected based on the functionality of the system and the complimentary nature to MP's existing assets

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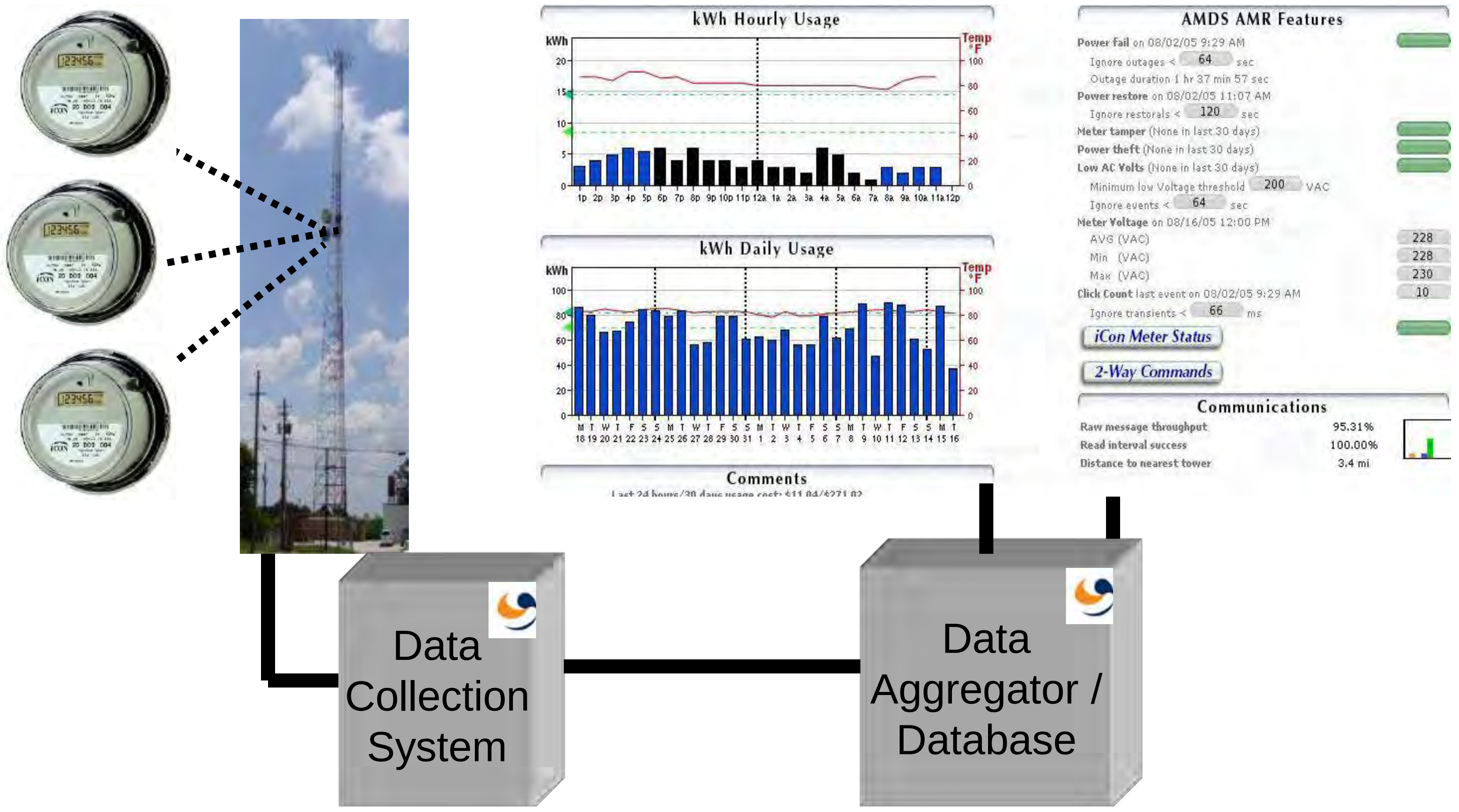
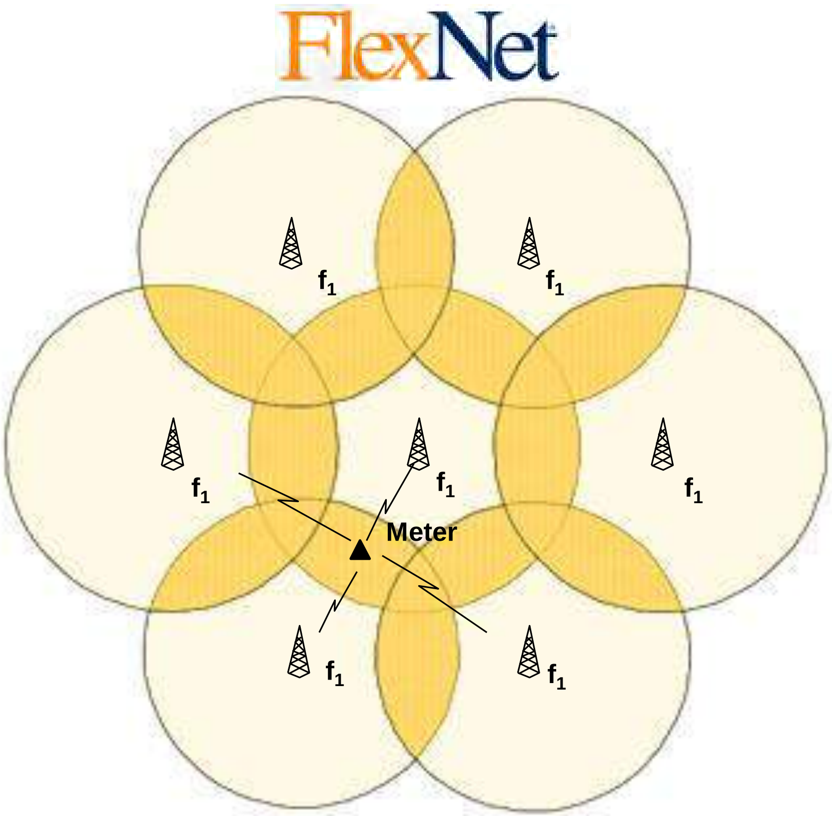
AMI System Overview



System Overview Cont'd…

- Tower Coverage's Ideally provide 50% Overlap with Adjacent Cells
- Creates Significant Signal Redundancy
- Single "Hop" Architecture for Mesh Network Between Meters



Provides Redundant Overlapping Coverage

Meter TOD Capability

- Meter Overview:
  - Up to 7 TOU Tiers
  - Up to 8 Seasons
  - Up to 24 holidays
  - Critical Peak Pricing (CPP) Dynamic Response

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Current Time-of-Day Offering

- On-Peak 8a-10p M-F/Off-Peak 10p-8a M-F + Weekends + Holidays
- Critical Peak Pricing
  - determined by market prices
  - Assumed at 25hr/yr
  - Capped at 50hr/yr
- Closed Pilot (400/660 participants remain)
- Much more detail in Docket No. E015/M-12-233

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Deployed with Plans for Future Enhancements

- Meter Data Management System
- Evaluate Other Alternative Rates
- Enhanced Revenue Protection
- Power Quality Monitoring
- Pilot Reporting Reliability Statistics (By Point)
- Demand Response

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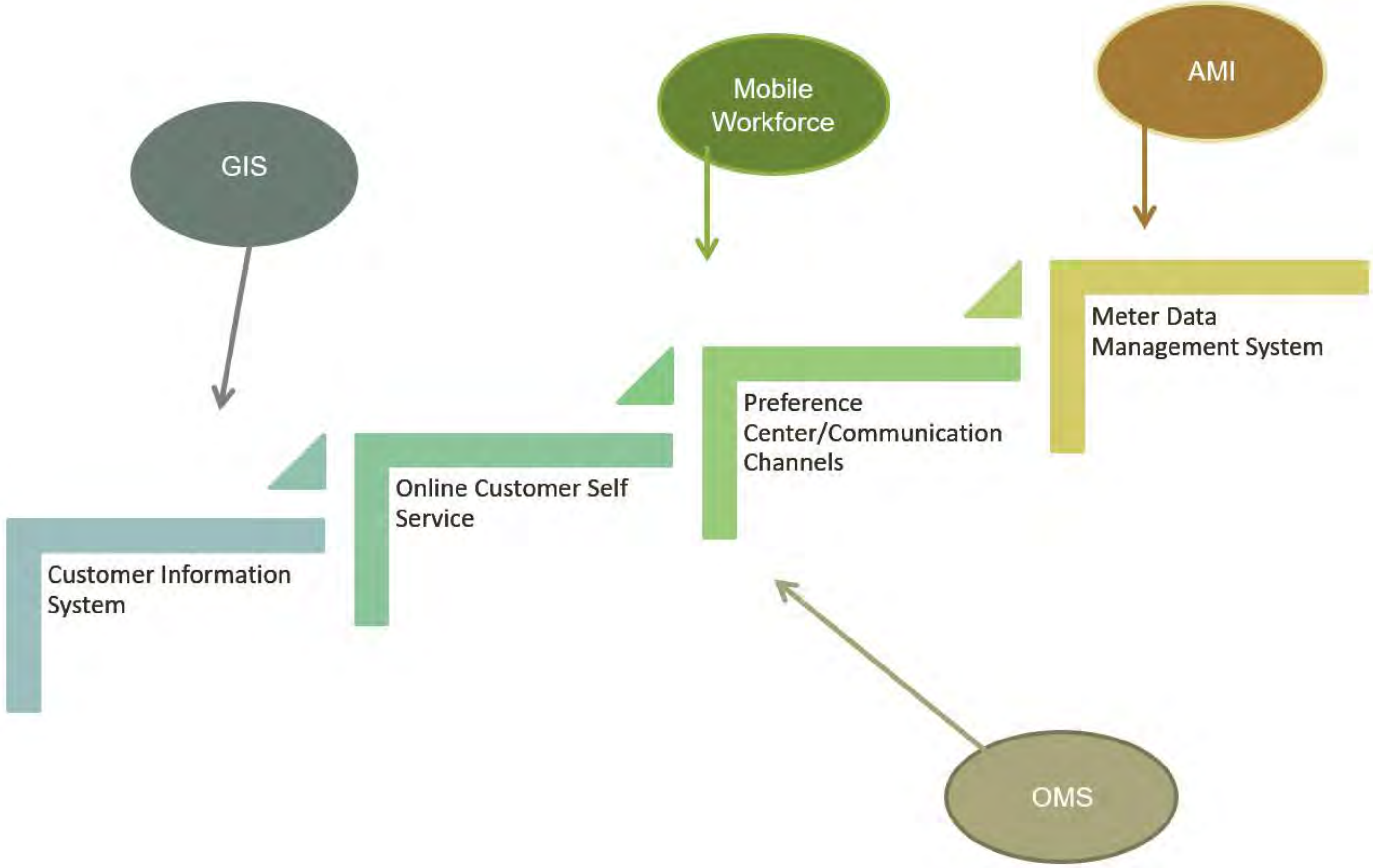
Technology & Data Integration



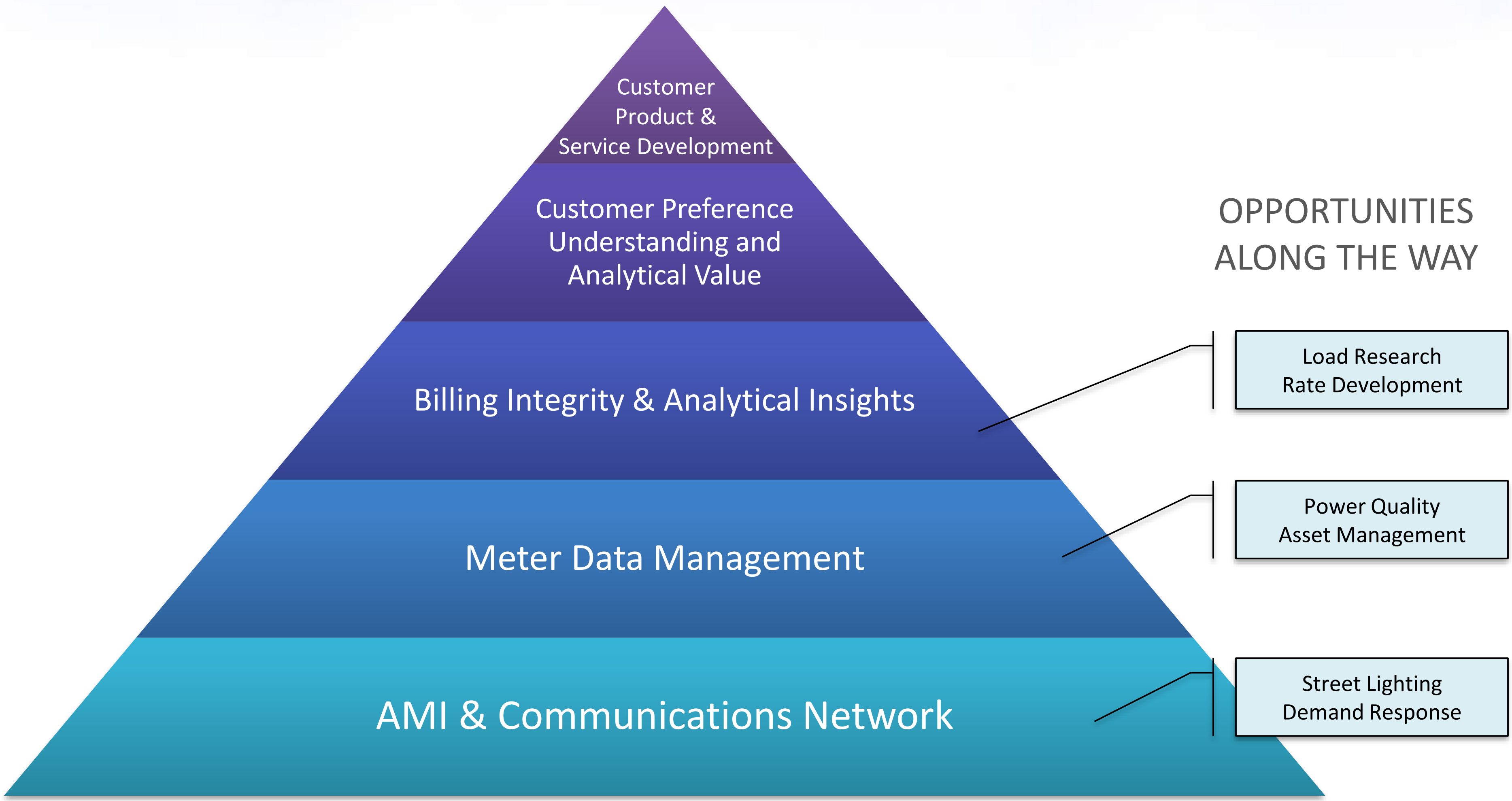
Current State – Need for MDM

- Validation, Estimation and Editing (VEE) of meter data
  - CIS are not designed to process, analyze or store mass volumes of data received from AMI
  - Interval data – up to 1,000,000 rows of data and only 50% deployed
  - Analysis
- Automation of meter alarm actions
- Enables complex billing and rates, including TOD
  - ~25% of current TOD customers require manual billing intervention
- Manage mass amounts of AMI meter data (5, 15, 60 minute interval data)
- Improves customer's view of their consumption through MyAccount
- Load analysis
- Power quality analysis
- Aggregation of meter data
- Demand Response flexibility

Benefits of an MDM

- Improved ability to investigate meter and service anomalies using events and alarms
- Improved power quality detection
- Better visibility of load data from aggregated meters
- Increase ability to identify and take action on meter failures and theft
- Increase integration with Outage Systems to reduce outage duration, increase accuracy of estimated restoration times, and reduce repeated customer calls to verify power status
- Facilitate access to business data and reporting
- Promote data-driven decision-making
- Establish and improve analytics
- Improved validation

Integration with Distribution System Platform



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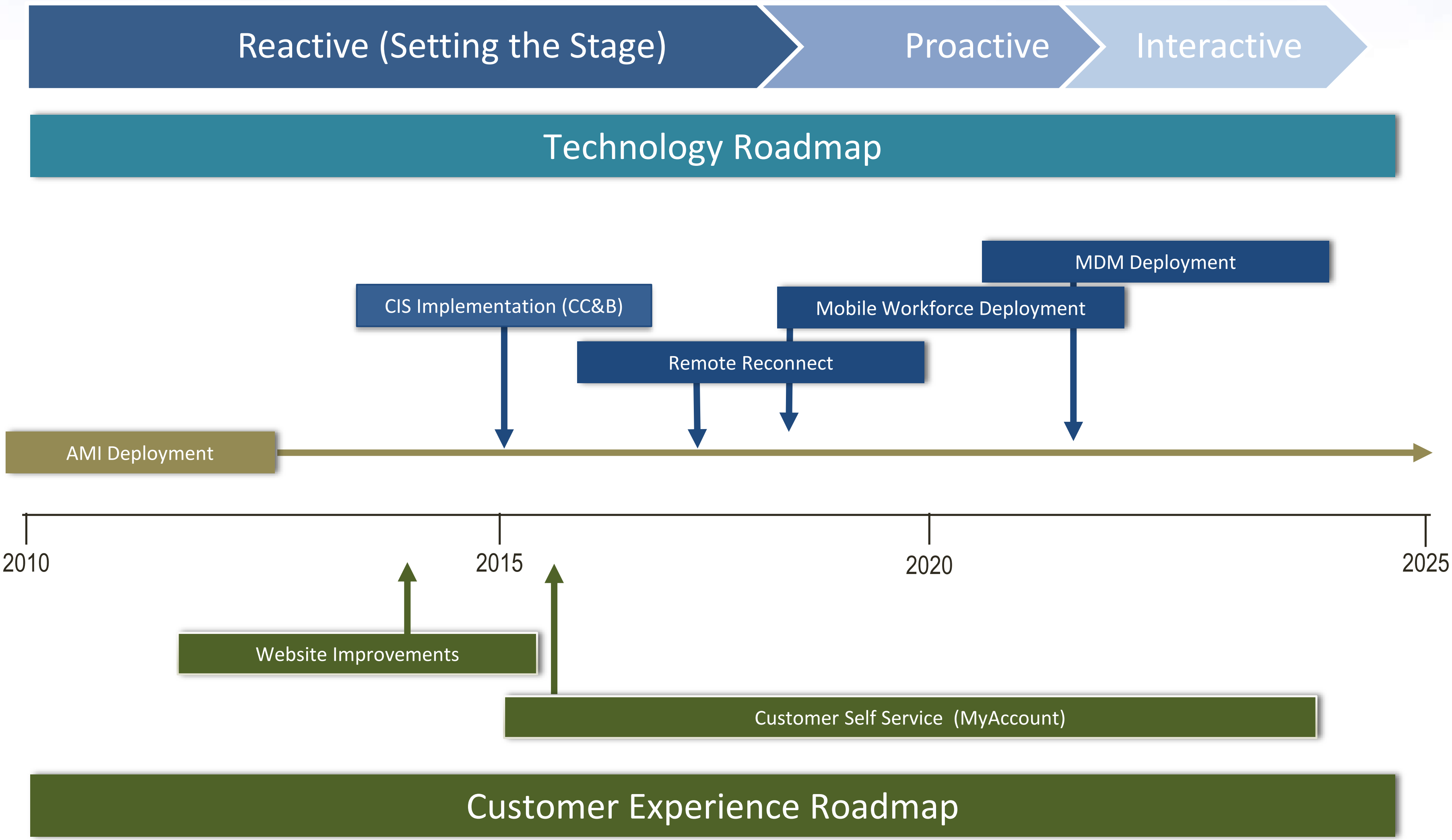
Roadmap and Timeline



Questions?

Minnesota Power Advanced Time of Day Rate
Meeting 2: September 28th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

9:00am – 12:30pm

For remote meeting access, please click this link at the meeting time:
https://betterenergy.zoom.us/j/275325095

Note: for optimal audio quality, we suggest using headphones or a headset

Draft Agenda

9:00-9:15am	Welcome, Intro's, Recap from Meeting 1
9:15-9:30am	Review Objectives and Design Principles
9:30-10:30am	Presentation: System Load Characteristics
10:30-10:45am	BREAK
10:45-11:15am	Presentation: Findings from Smart Grid Pilot
11:15-12:15pm	Discussion: Objectives, Design Principles, Roll-out Plan
12:15-12:30pm	Reflection, Wrap-up, and Next Steps
12:30pm	ADJOURN

MINNESOTA POWER SYSTEM LOAD CHARACTERISTICS

SEPTEMBER 28, 2018

Lon Huber
Director

minnesota power

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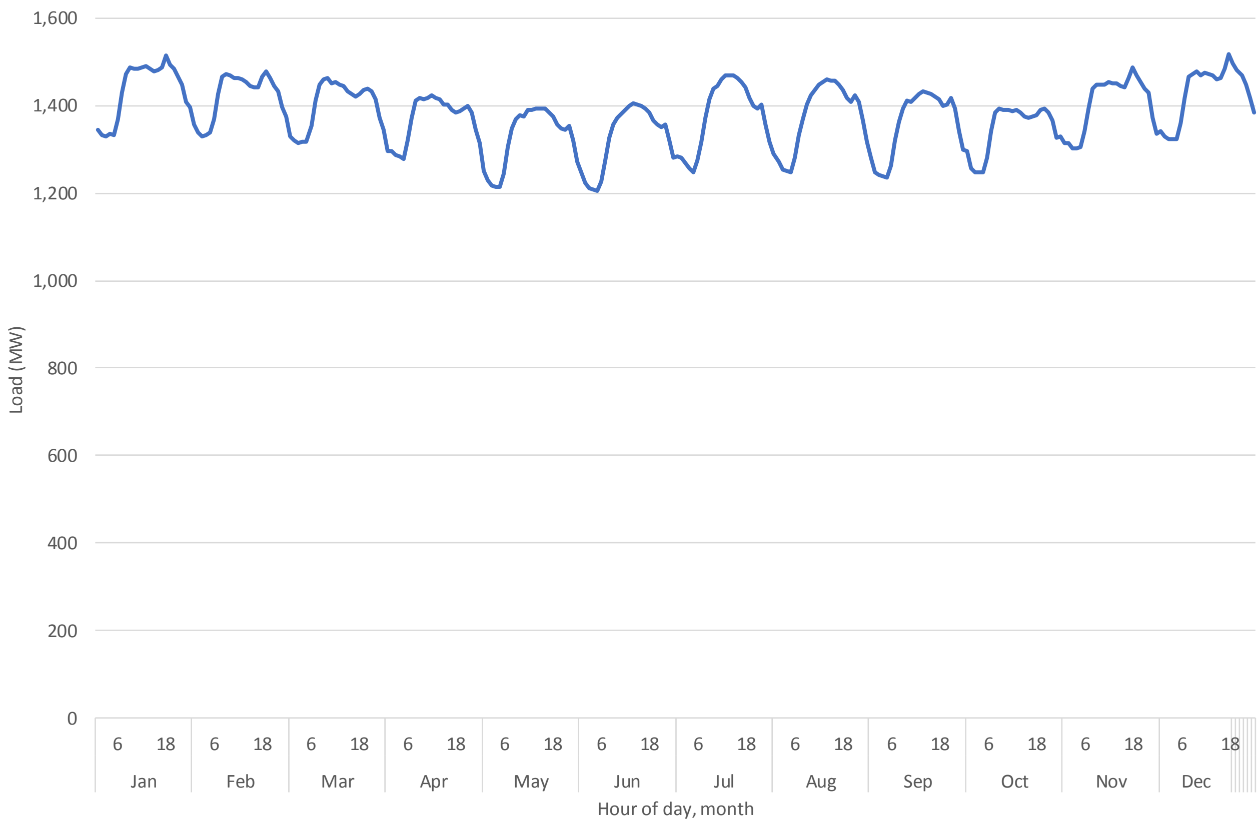
Attachment A

GROSS SYSTEM PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



- Load is relatively flat across the year and across the day when compared with other utilities, driven by high share of large industrial load
- 74% industrial
- Peak in winter, with summer higher than shoulder seasons
- Average gross load is equal to 89% of peak gross load

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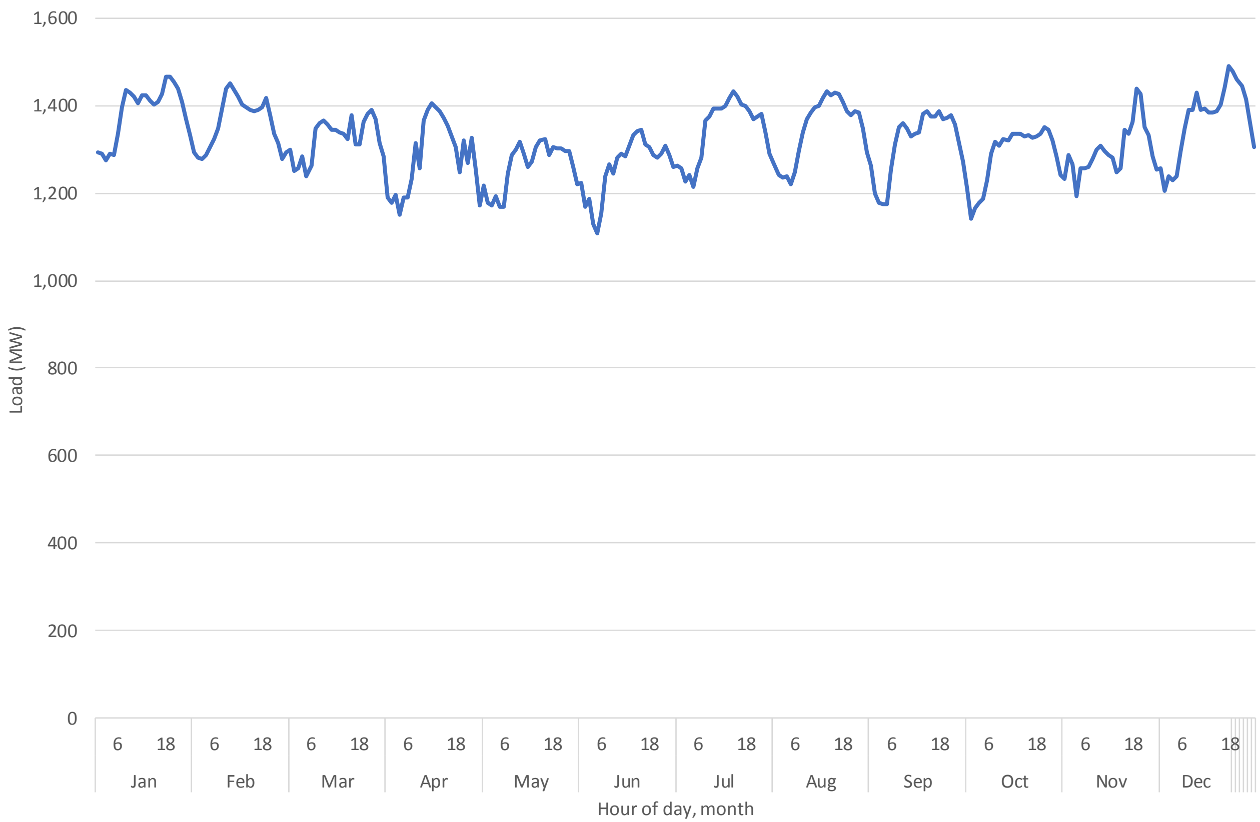
NET SYSTEM PEAK LOAD*
BY TIME OF DAY AND MONTH - 2020



- More variability than gross load, but still relatively flat
- Includes planned additions of renewable generation

- Net load is gross load less wind and solar generation
- The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)

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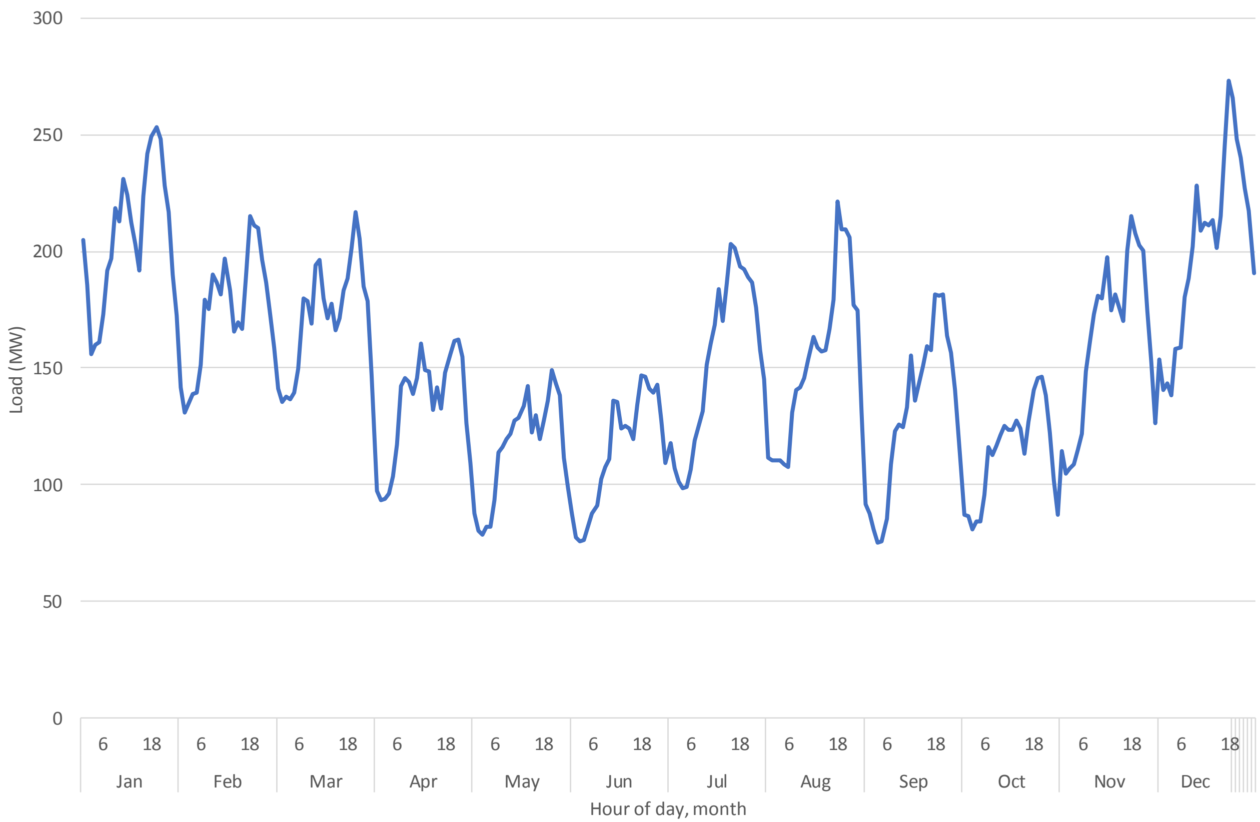
RESIDENTIAL PEAK LOAD BY TIME OF DAY AND MONTH - 2020



- Residential load shows much more variability than system load, both within a day and between seasons
- Strong winter evening peak
- Average residential load is equal to 51% of peak residential load

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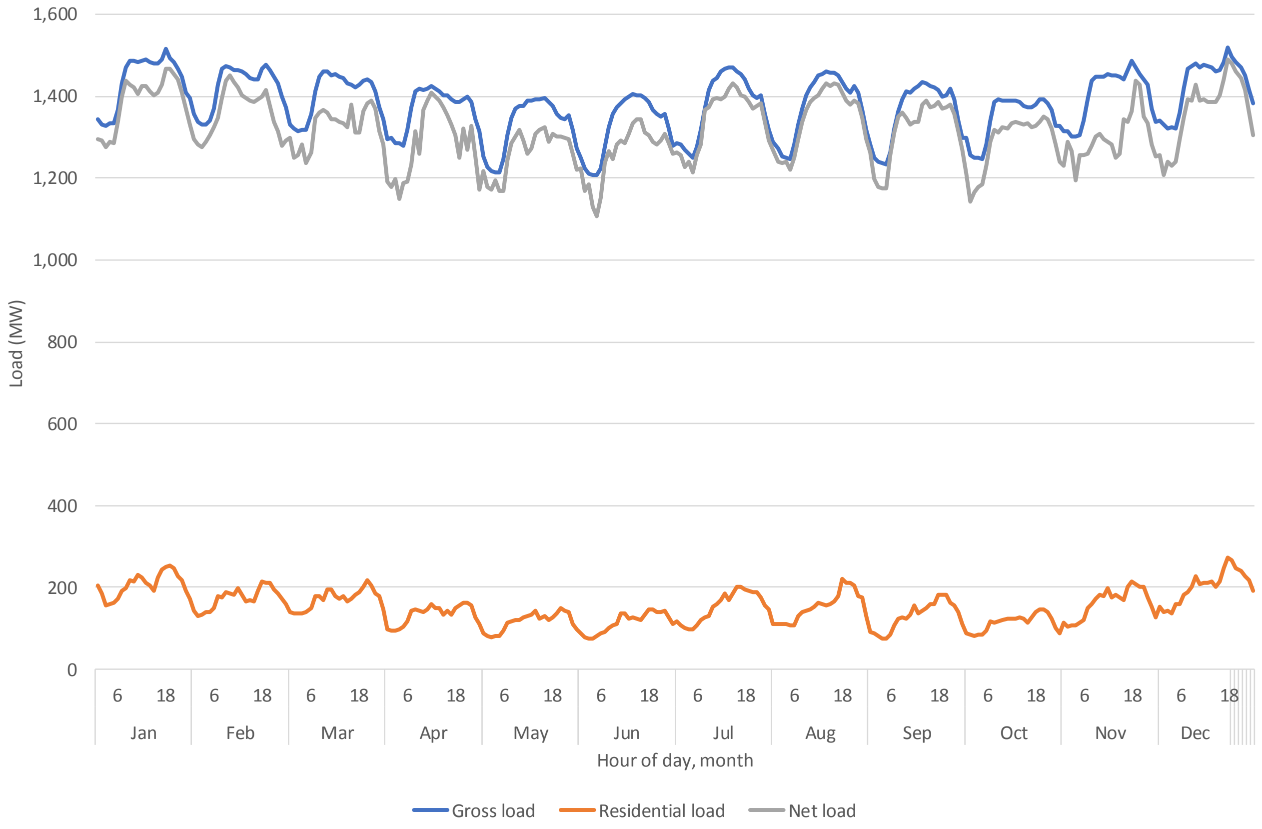
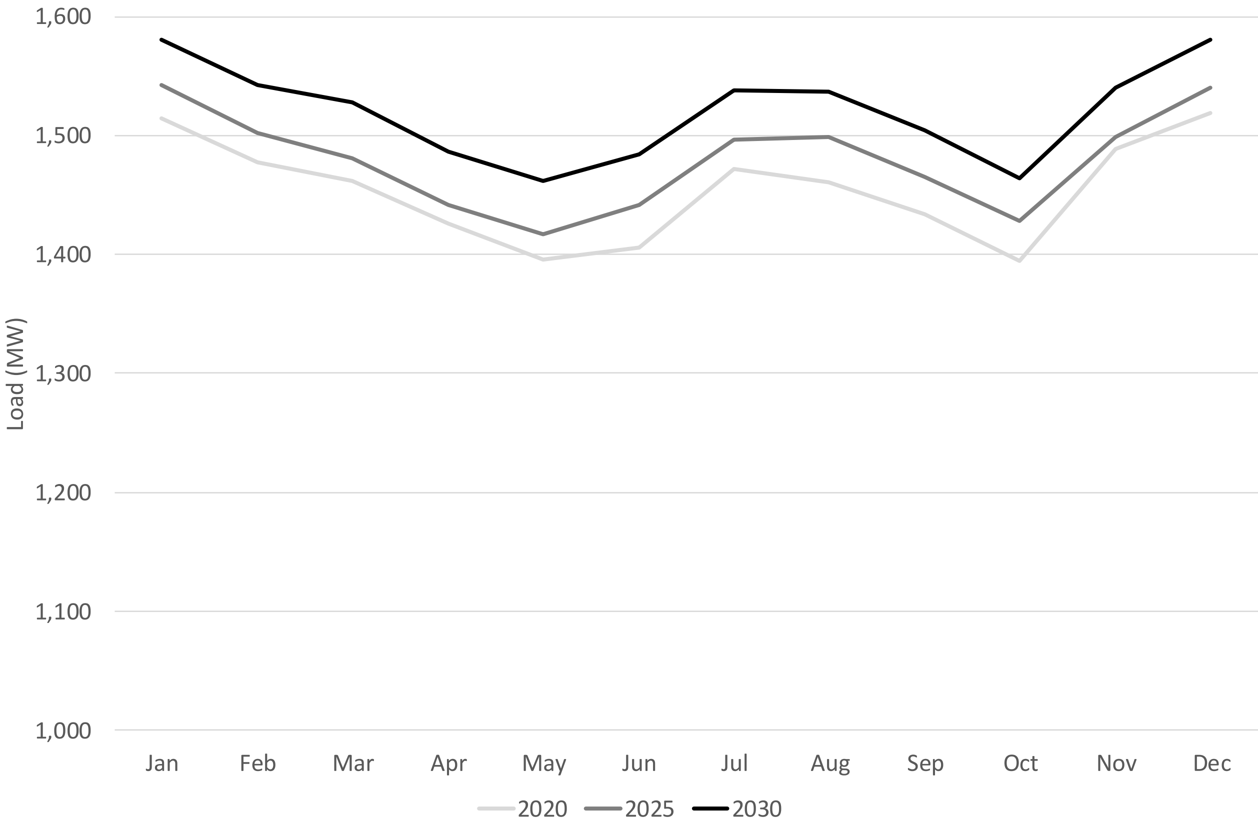
PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



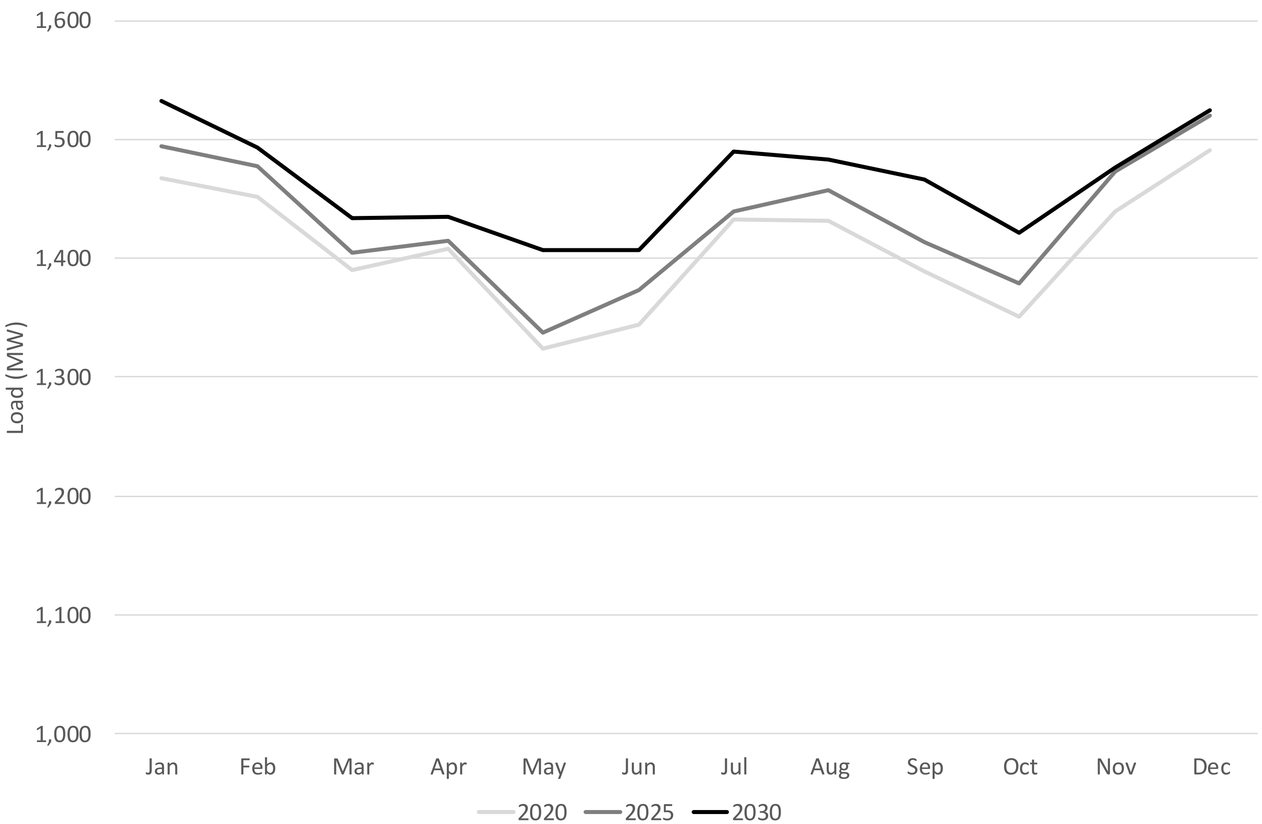
- Residential load makes up less than 10% of gross load, a small share when compared with other utilities

PROJECTED SYSTEM PEAK GROSS LOAD BY MONTH



- 4% peak growth projected from 2020 to 2030 for both winter and summer peaks

PROJECTED SYSTEM PEAK NET LOAD* BY MONTH



- Peak net load projected to drop in the short term and then return to 2017 level by 2030
- Short-term drop driven by growth in wind and solar generation
- Flat growth within error range

* Net load is gross load less wind and solar generation

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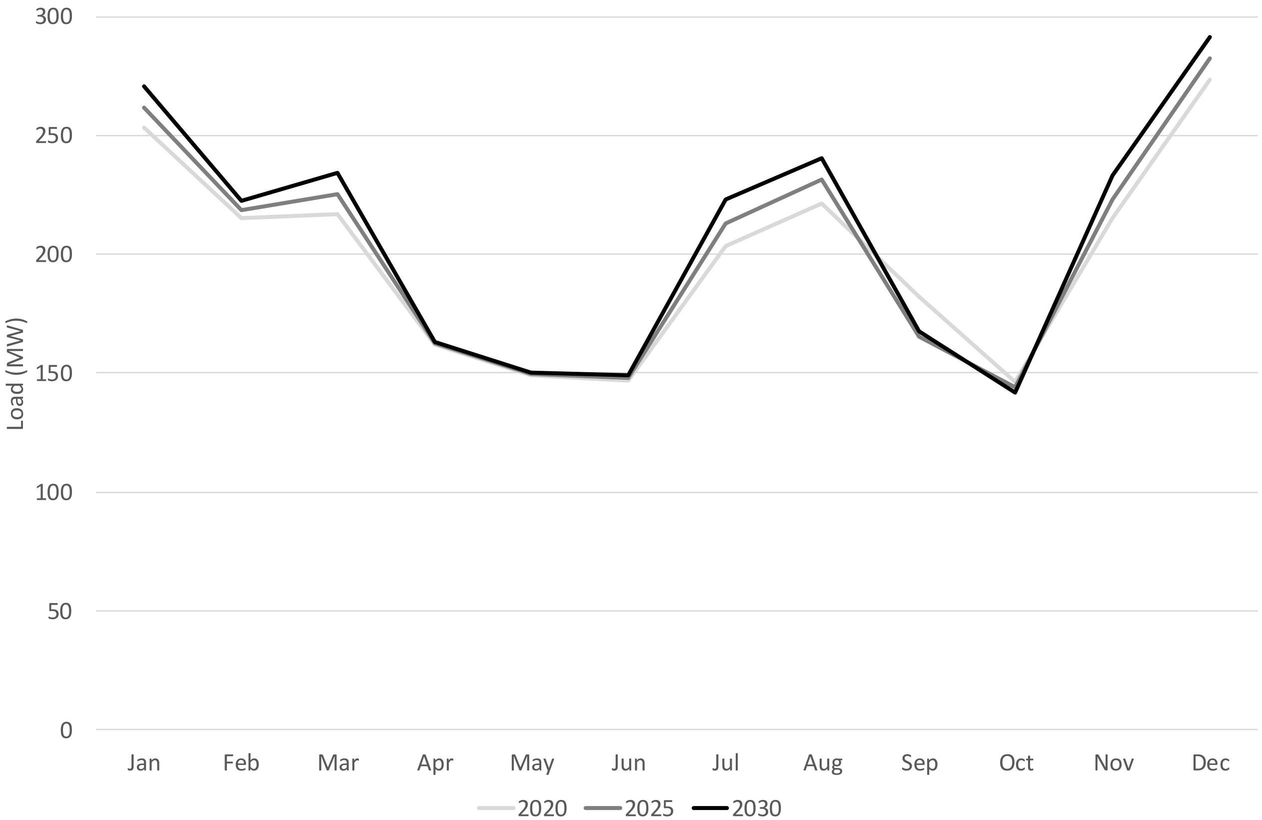
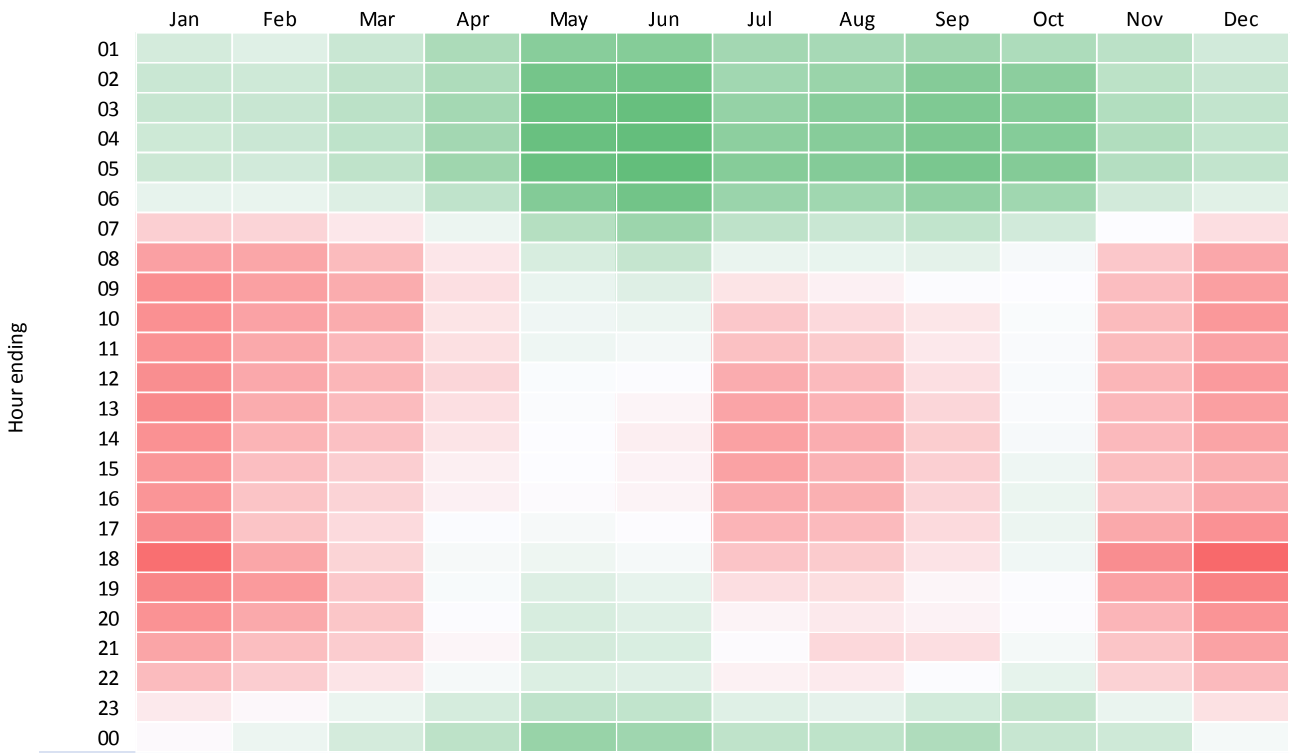
PROJECTED PEAK RESIDENTIAL LOAD BY MONTH



- 7% (20 MW) peak growth projected from 2020 to 2030

GROSS SYSTEM LOAD HEAT MAP - 2020



- Seasonal and day/night patterns
- Load highest on winter days
- Low load overnight
- Generally lower load in shoulder seasons (spring, fall)
- Range 1,150 MW – 1,550 MW

Red – high load, green – low load

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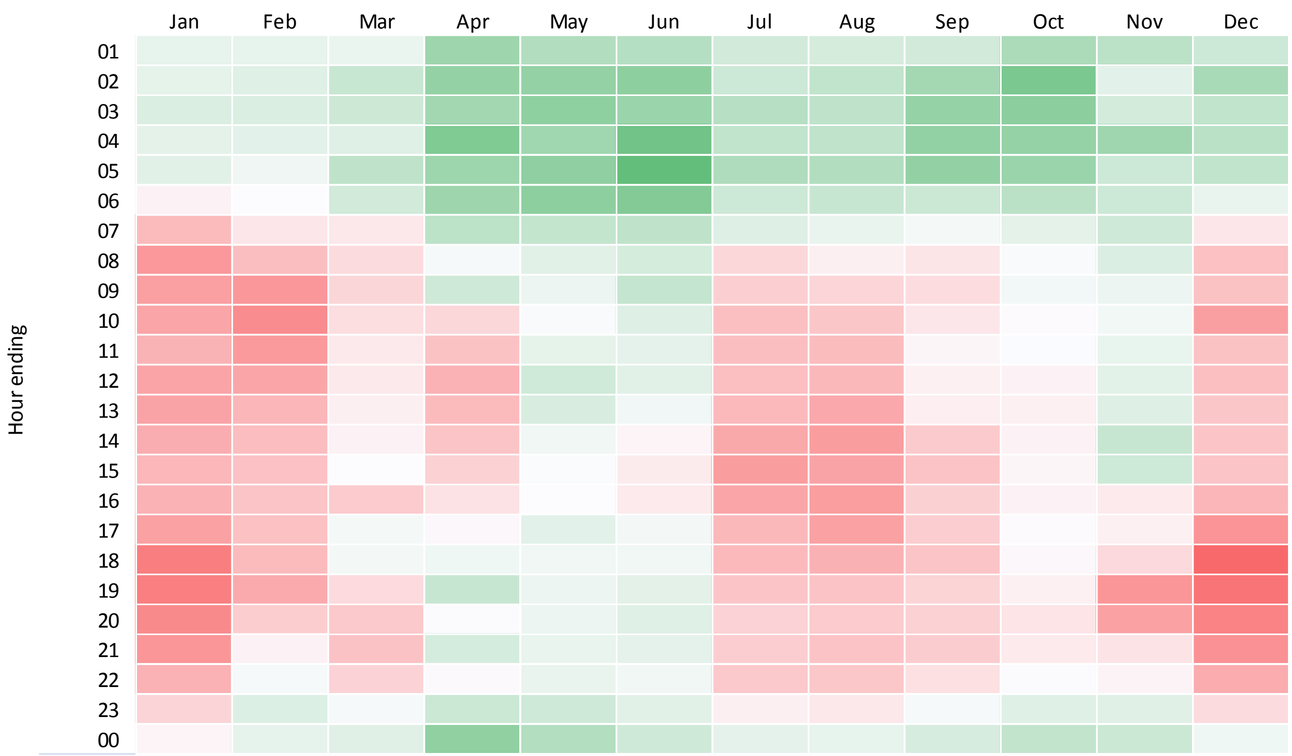
NET SYSTEM LOAD HEAT MAP - 2020



- Similar pattern to gross load (with more variability)
- Seasonal and day/night patterns
- Net load highest on summer and winter days
- Low load overnight
- Generally lower load in shoulder seasons (spring, fall)
- Range 350 MW – 1,500 MW

Red – high load, green – low load

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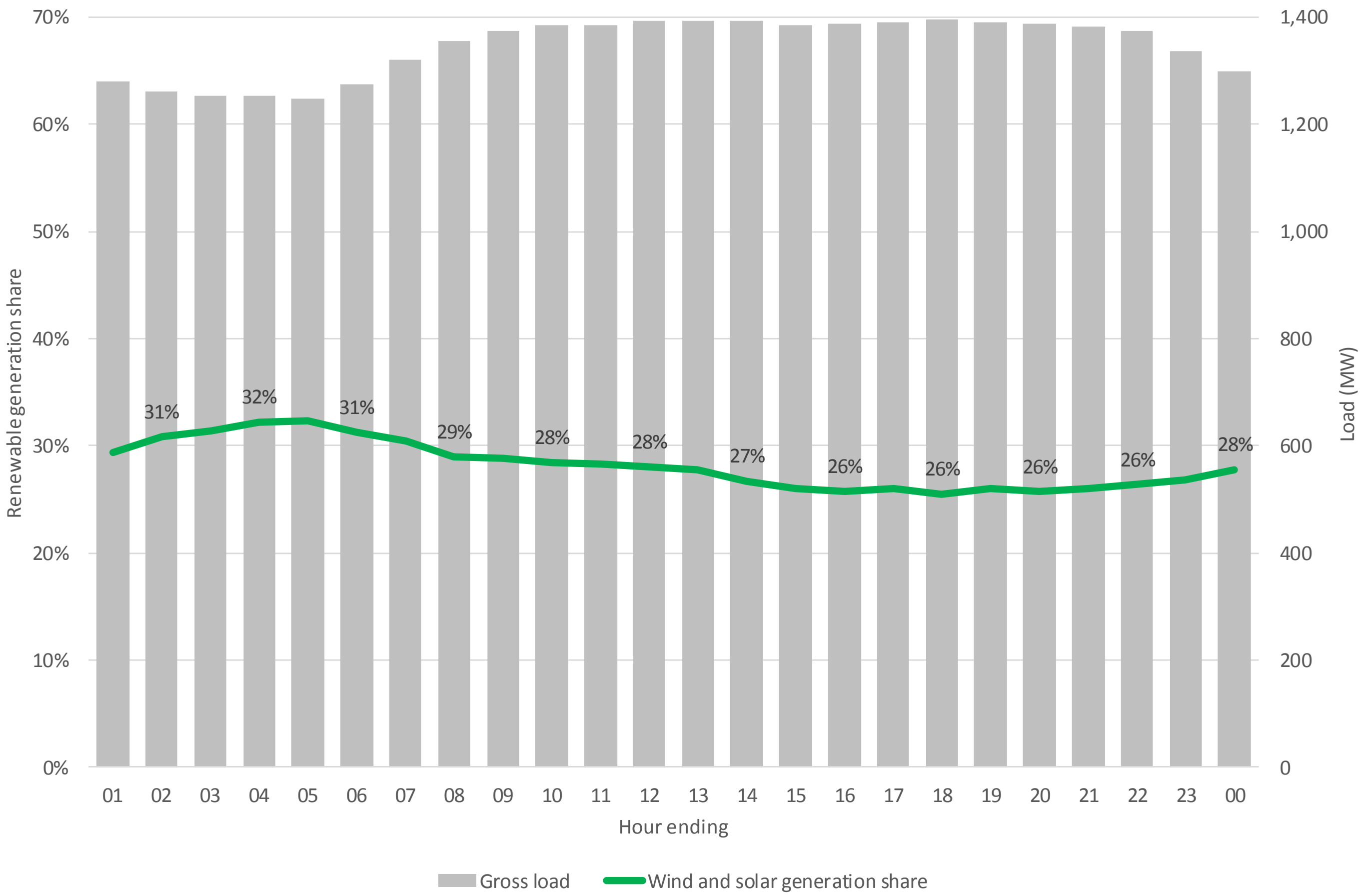
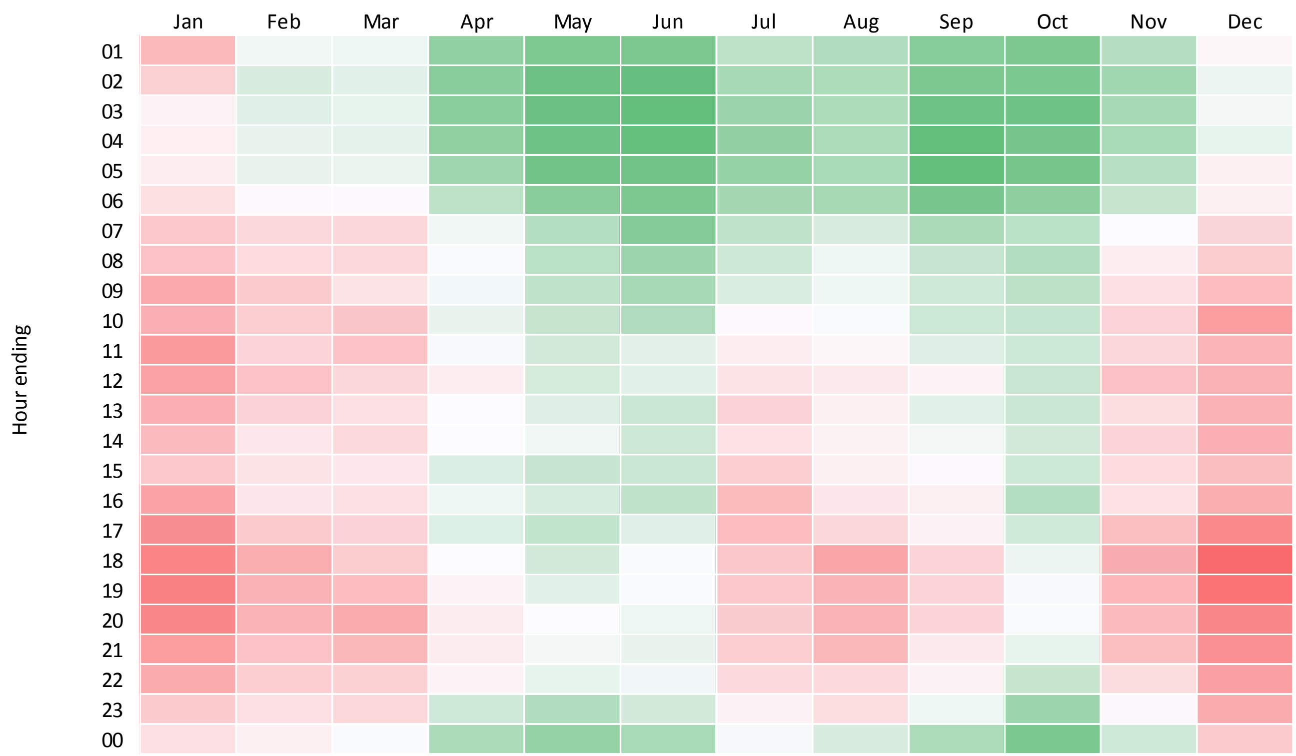
RENEWABLE SHARE OF GENERATION IS HIGHEST OVERNIGHT



- The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)
- Data is average projected load and renewable generation by hour for 2020

RESIDENTIAL LOAD HEAT MAP - 2020

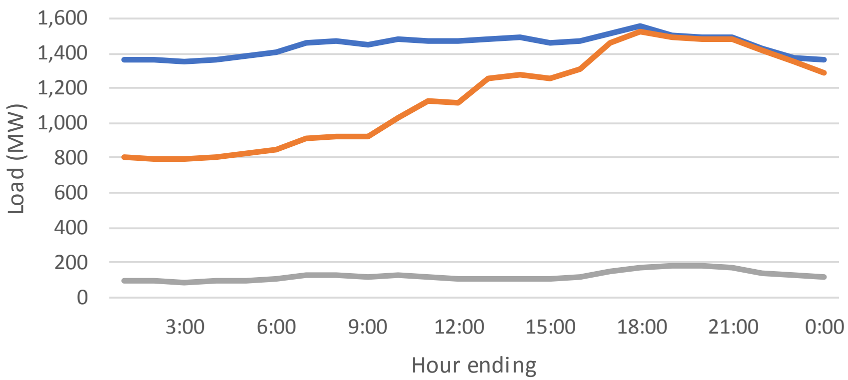


- Seasonal and day/night patterns
- Load highest on winter evenings and mornings
- Low load overnight
- Generally low load in shoulder seasons (spring, fall)
- Range 50 MW – 275 MW

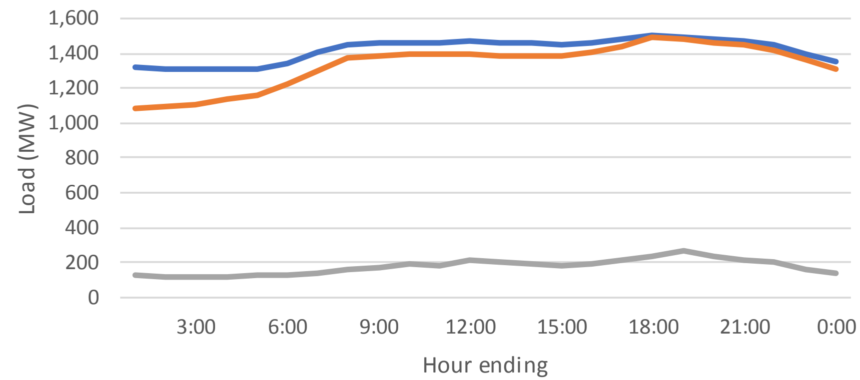
Red – high load, green – low load

PEAK DAYS – BASED ON NET SYSTEM LOAD

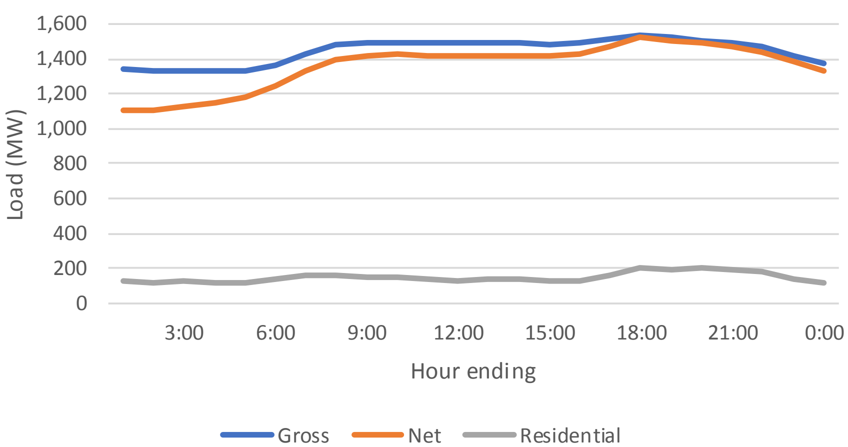
2017 (Nov weekday 6pm)



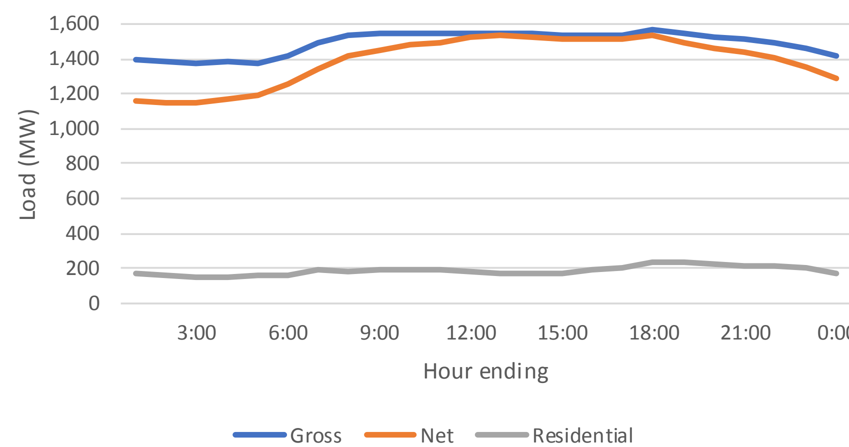
2020 (Dec weekday 6pm)



2025 (Dec weekday 6pm)



2030 (Jan weekday 6pm)



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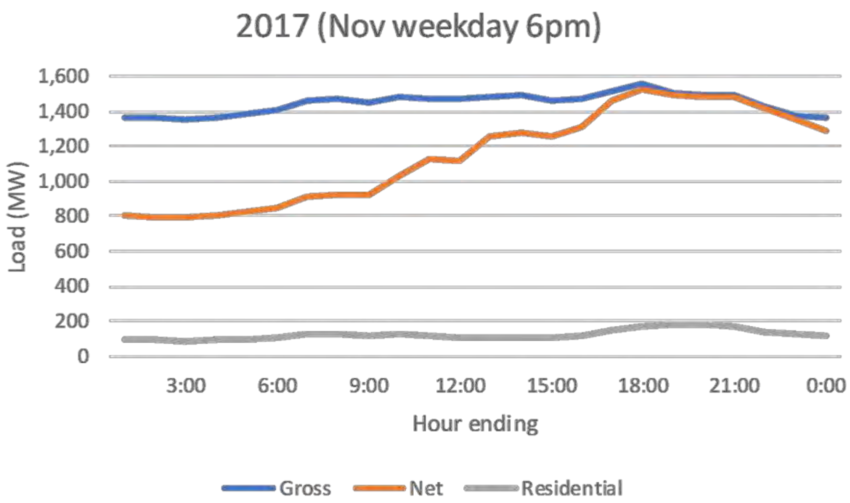
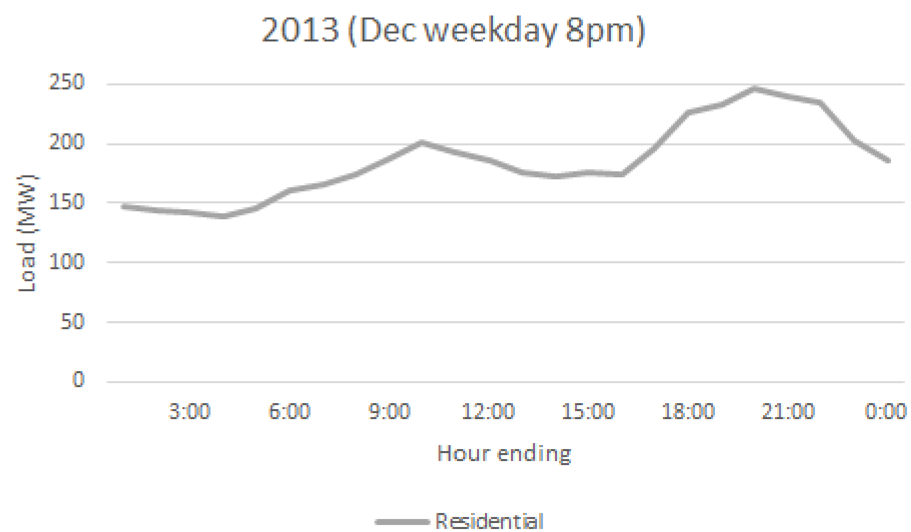
ZOOM: 2017 NET PEAK DAY - TUE 21 NOV

	Net load	Percentage of peak load	Residential load	Residential share of net load
1:00	803	53%	90	11%
2:00	797	52%	91	11%
3:00	794	52%	88	11%
4:00	805	53%	91	11%
5:00	827	54%	93	11%
6:00	851	56%	104	12%
7:00	908	60%	127	14%
8:00	926	61%	129	14%
9:00	925	61%	116	13%
10:00	1,030	68%	126	12%
11:00	1,125	74%	112	10%
12:00	1,115	73%	106	10%
13:00	1,252	82%	106	8%
14:00	1,278	84%	103	8%
15:00	1,258	82%	102	8%
16:00	1,307	86%	115	9%
17:00	1,464	96%	146	10%
18:00	1,525	100%	170	11%
19:00	1,495	98%	179	12%
20:00	1,484	97%	176	12%
21:00	1,476	97%	172	12%
22:00	1,416	93%	143	10%
23:00	1,356	89%	127	9%
0:00	1,284	84%	113	9%



ZOOM: 2013 RESIDENTIAL PEAK DAY – MON 23 DEC

	Residential load	Percentage of peak load
1:00	148	60%
2:00	143	58%
3:00	142	58%
4:00	140	57%
5:00	146	59%
6:00	162	66%
7:00	167	68%
8:00	174	71%
9:00	187	76%
10:00	202	82%
11:00	193	79%
12:00	186	75%
13:00	176	72%
14:00	173	70%
15:00	175	71%
16:00	175	71%
17:00	195	79%
18:00	226	92%
19:00	232	94%
20:00	246	100%
21:00	239	97%
22:00	235	95%
23:00	203	82%
0:00	187	76%



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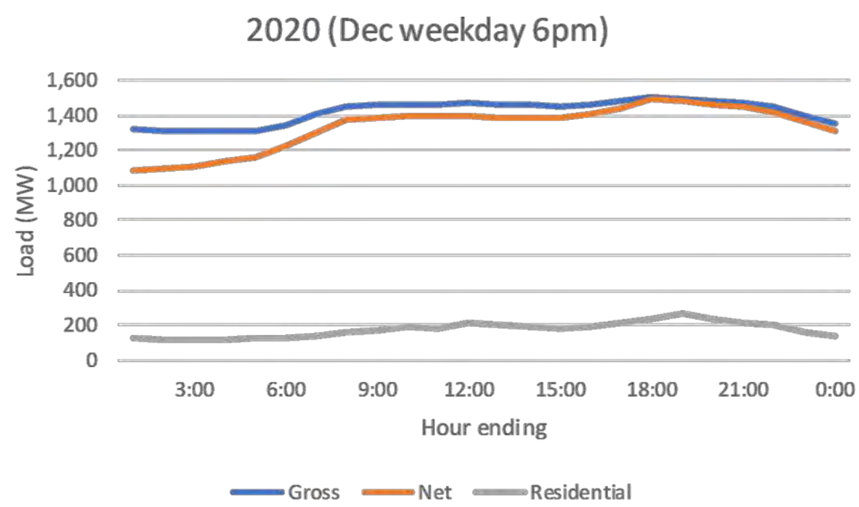
ZOOM: 2020 NET PEAK DAY – DEC WEEKDAY

	Net load	Percentage of peak load	Residential load	Residential share of net load
1:00	1,086	73%	122	11%
2:00	1,089	73%	117	11%
3:00	1,103	74%	119	11%
4:00	1,132	76%	120	11%
5:00	1,164	78%	123	11%
6:00	1,222	82%	128	10%
7:00	1,304	87%	142	11%
8:00	1,369	92%	163	12%
9:00	1,389	93%	171	12%
10:00	1,398	94%	193	14%
11:00	1,390	93%	184	13%
12:00	1,393	93%	208	15%
13:00	1,385	93%	199	14%
14:00	1,386	93%	197	14%
15:00	1,387	93%	177	13%
16:00	1,403	94%	188	13%
17:00	1,442	97%	207	14%
18:00	1,491	100%	234	16%
19:00	1,479	99%	266	18%
20:00	1,462	98%	236	16%
21:00	1,444	97%	215	15%
22:00	1,414	95%	207	15%
23:00	1,361	91%	154	11%
0:00	1,306	88%	138	11%



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MISO LMP HEAT MAP

Hour ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01	28	29	25	21	22	21	21	25	14	16	25	26
02	27	28	25	21	21	20	19	23	12	16	24	25
03	26	28	25	21	20	19	18	23	12	16	24	25
04	26	28	25	22	22	20	18	23	14	17	24	25
05	27	29	29	28	26	22	20	25	19	24	28	27
06	33	36	37	36	32	28	23	28	24	34	34	31
07	46	44	45	42	37	33	28	33	32	37	40	40
08	48	45	46	44	40	35	32	36	35	38	41	43
09	48	46	47	44	41	37	38	39	37	39	42	42
10	48	47	47	42	42	40	42	42	39	40	42	42
11	46	45	45	40	42	42	47	45	39	39	41	41
12	43	42	42	37	41	43	51	48	40	37	38	39
13	41	40	40	36	40	45	57	52	40	36	37	37
14	38	38	37	34	38	47	62	57	41	35	36	36
15	37	37	36	33	37	47	68	59	40	34	35	35
16	37	37	35	32	37	46	67	57	40	34	35	37
17	47	40	36	31	36	44	60	53	39	36	45	52
18	61	52	42	32	35	41	53	48	39	48	53	56
19	53	52	50	42	38	39	47	47	42	45	46	49
20	49	47	47	43	41	40	47	46	39	37	42	45
21	44	42	39	33	35	39	42	39	34	31	37	41
22	38	36	34	27	30	33	30	33	28	26	33	37
23	32	34	28	24	26	29	27	29	20	21	31	32
00	29	30	26	22	24	23	23	27	16	18	27	27

- Highest prices on summer afternoons and winter evenings
- Low prices overnight
- Seasonal variation less pronounced than for load
- Prices more aligned to MISO-wide load conditions than Minnesota Power load

Red – high price, green – low price

Data: MP-projected average LMP by hour by month at MP.MP_BOS4 node, 2020

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INDICATIVE MARGINAL COSTS

Function	Source	Cost (2020$/kW-year)	Cost (2020 Cents/kWh)*
Transmission	Mendota Group analysis of 30 US utilities (2014)	$25	1.7
Distribution	Mendota Group analysis of 30 US utilities (2014)	$52	3.5
Generation Capacity	Gross CT Cost of New Entry (LRZ 1)	$95	6.5
Energy	Residential load weighted LMP from 6 – 10 PM (2020)	N/A	4.3
Total Rate During Peak Hours		**N/A**	**16.0**

**Fixed costs are spread across the hours from 6-10PM, corresponding to Minnesota Power residential peak loads. Includes losses.*

Sample T&D Marginal Costs ($/kW-year)	Tx	Dx
Otter Tail Power (2016)	$72	$31
Xcel Energy (2014)	$14	$39
Mendota Group analysis average value (2014)	$22	$46

IMPLICATIONS FOR DESIGNING AN EFFECTIVE TOU RATE

Capacity type	Required based on	Load characteristics	Implication
Generation	Peak net system load	• Relatively constant • Day / night variability • Limited seasonal variability	TBD
Transmission	Peak gross system load		
Distribution	Peak residential load	• Significant intra-day and seasonal variability • Winter evening highest load period	More targeted peak period definition, e.g. winter evenings only

Rate design will need to take account of peak periods for different types of capacity, and balance these with other factors such as consistency, predictability and simplicity.

CONTACTS

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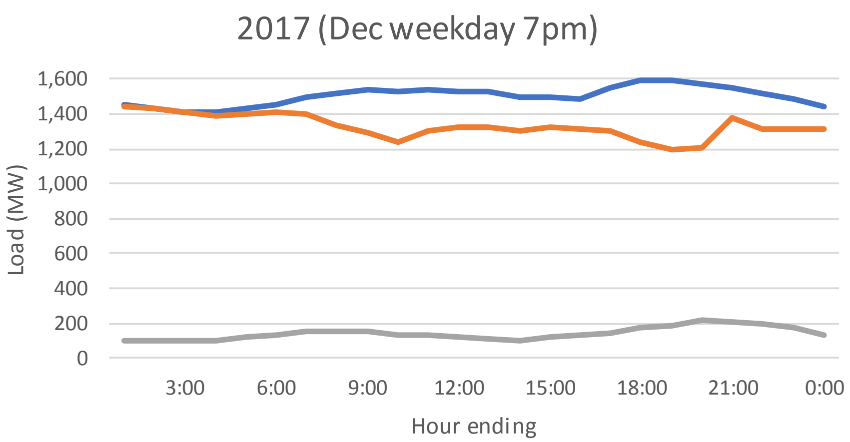
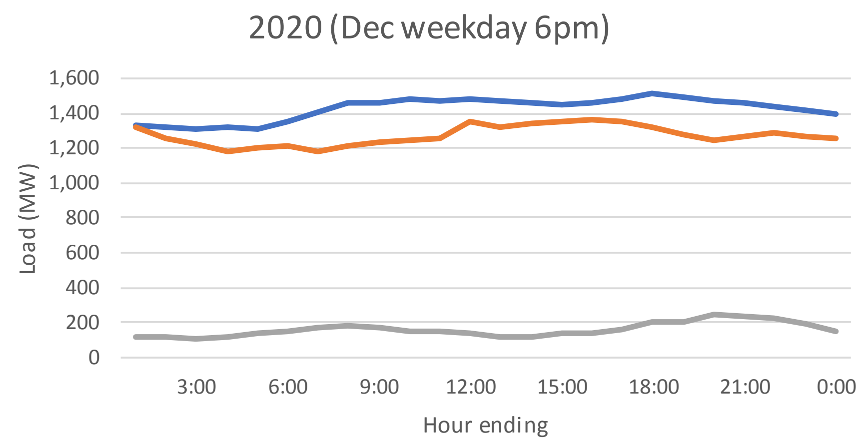
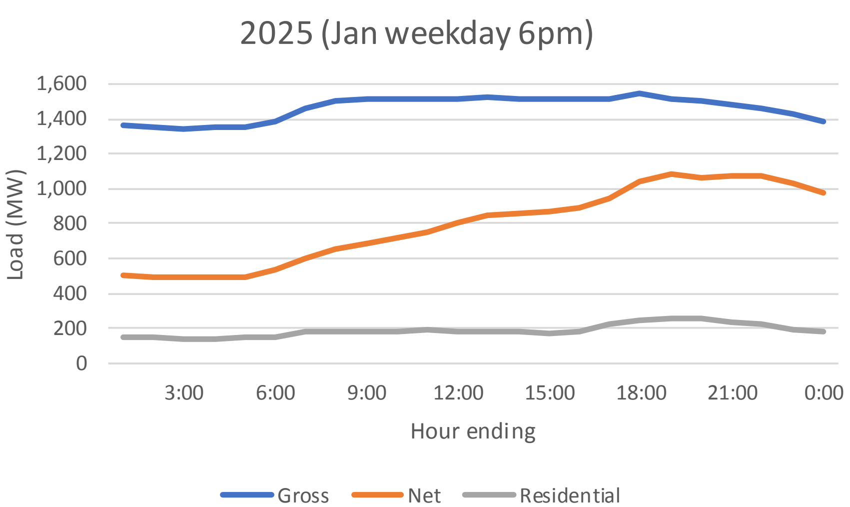
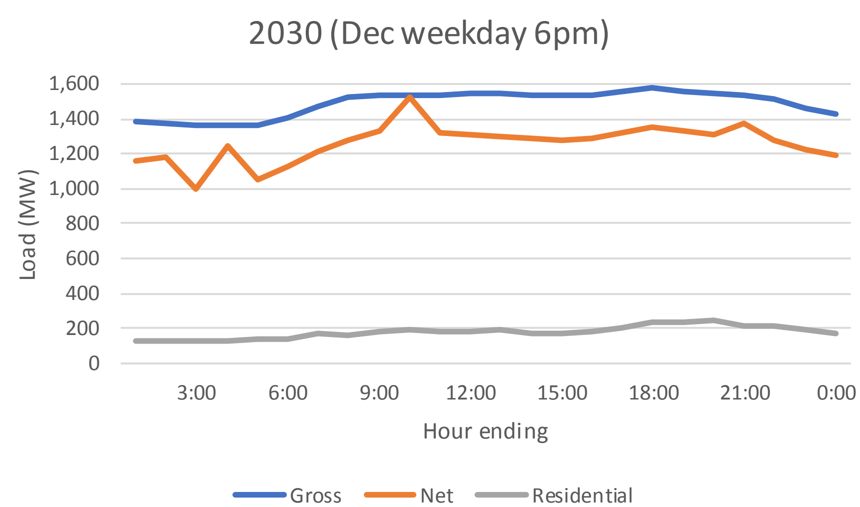
SUPPLEMENTARY MATERIAL

PEAK DAYS – BASED ON GROSS SYSTEM LOAD







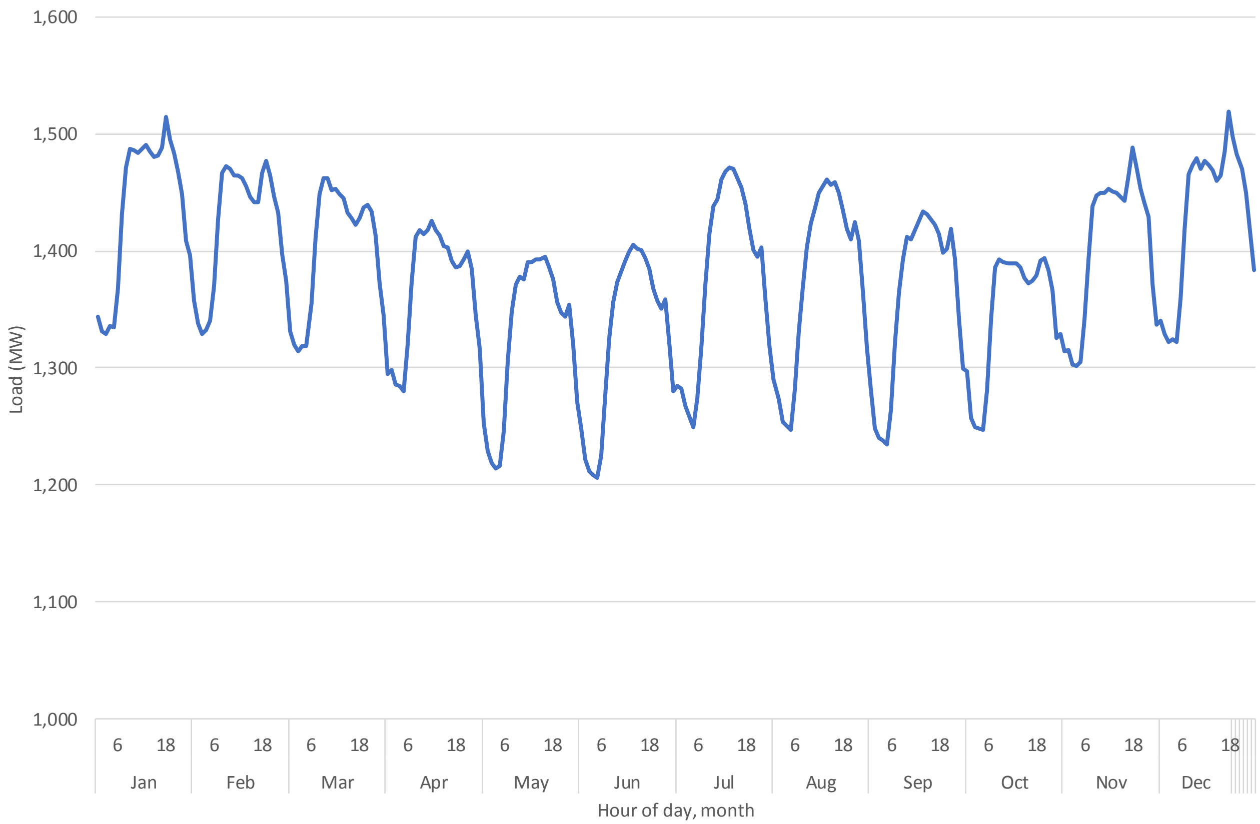


MP TOD RATE PILOT – CURRENT RATES

	Standard Rate	Off-peak Discount of $0.0299 calculated rate in this column	On-peak Increase of $0.04870 calculated rate in this column	Critical Peak Increase of $0.77 calculated rate in this column
0-300kWh ($/kWh)	$0.05098	$0.02108	$0.09968	$0.82098
301-500kWh ($/kWh)	$0.06735	$0.03745	$0.11605	$0.83735
501-750kWh ($/kWh)	$0.08168	$0.05178	$0.13038	$0.85168
751-1,000kWh ($/kWh)	$0.08445	$0.05455	$0.13315	$0.85445
> 1,000kWh ($/kWh)	$0.08937	$0.05947	$0.13807	$0.85937

Source: Minnesota Power Time-of-Day Rate Pilot

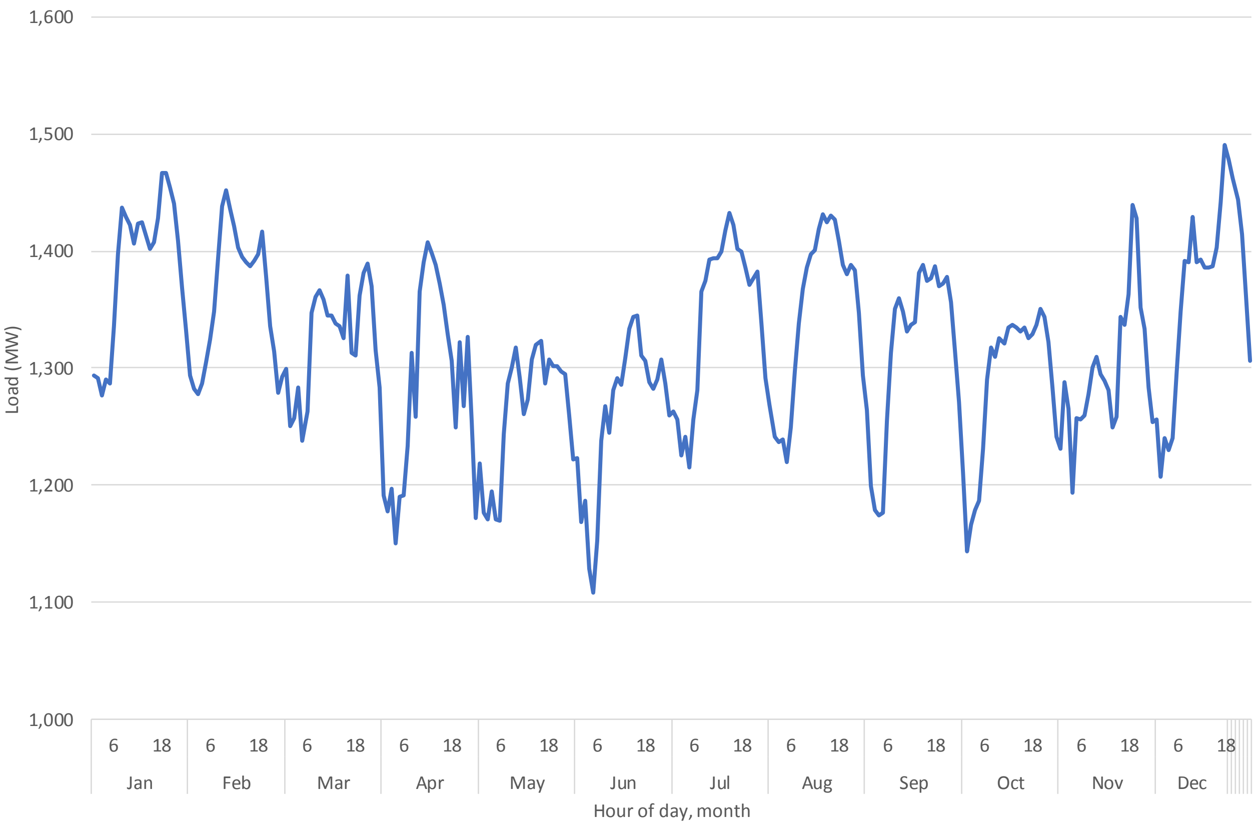
GROSS SYSTEM PEAK LOAD BY TIME OF DAY AND MONTH - 2020



- Load is relatively flat across the year and across the day when compared with other utilities, driven by high share of large industrial load
- Peak in winter, with summer higher than shoulder seasons

Attachment A

NET SYSTEM PEAK LOAD*
BY TIME OF DAY AND MONTH - 2020



- More variability than gross load, but still relatively flat
- Includes planned additions of renewable generation

- *Net load is gross load less wind and solar generation*
- *The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)*

NAVIGANT

CPP impacts for Minnesota Power's Time-of-Date Pilot

Scott Pigg

September 2018

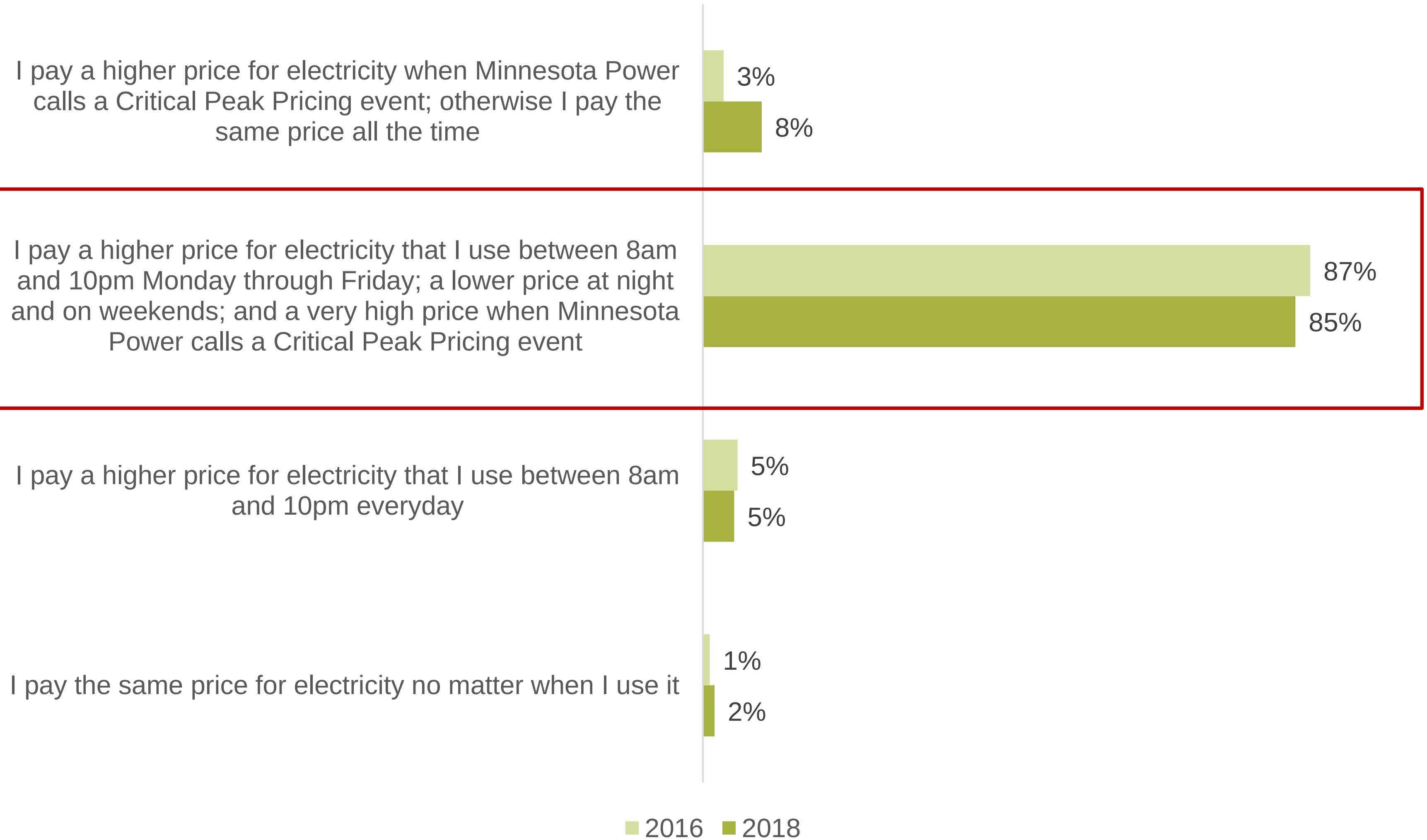
Scope

- Analyzed Critical Peak Pricing component of pilot rate
- Two analysis rounds
  - 6 events in 2015
  - 16 events in 2017/2018
- Conducted participant surveys
- Analyzed load impacts from metering data

Key Participant Characteristics

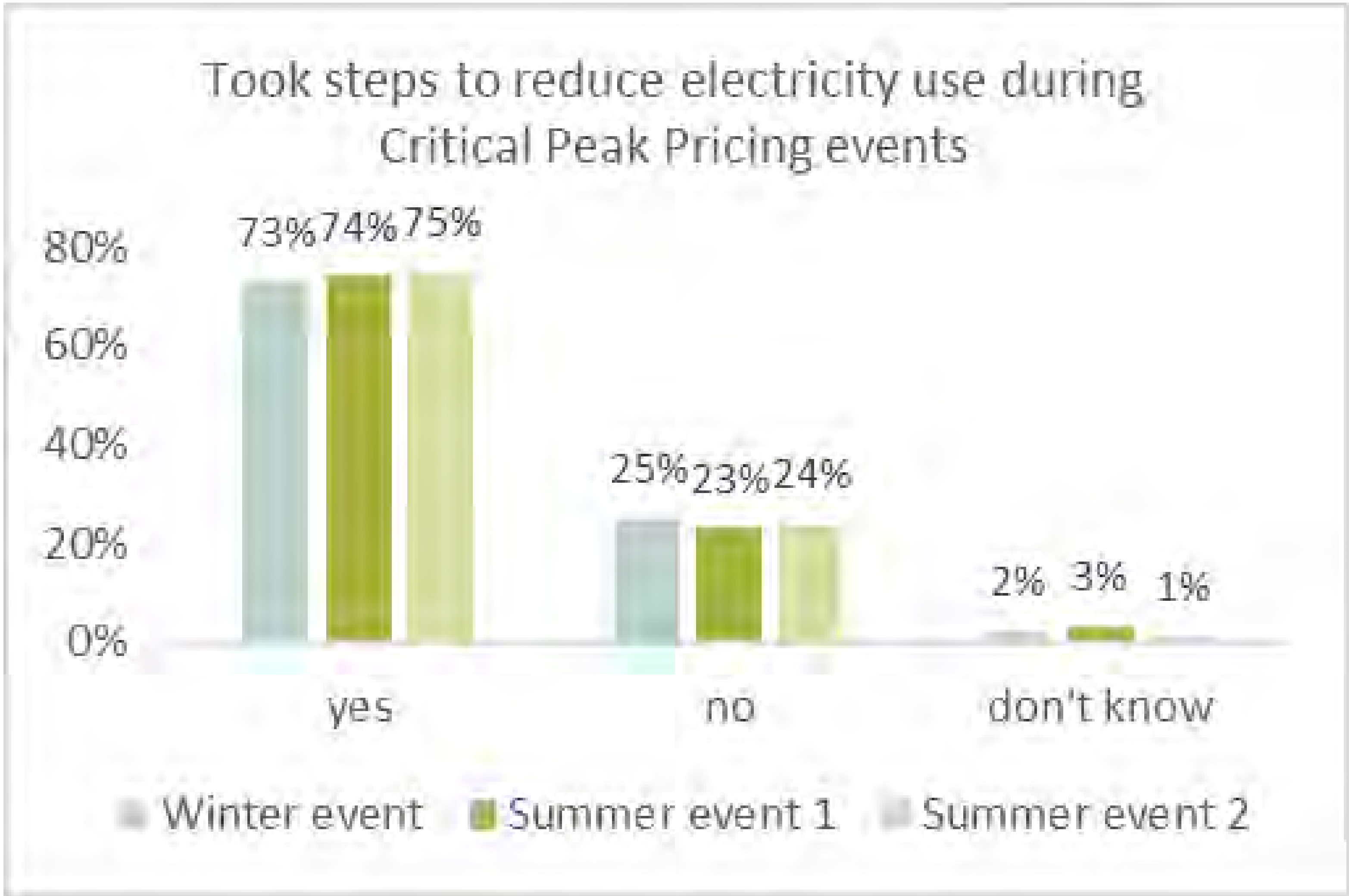
- Overwhelmingly single-family homeowners
  - 23% family w/ children
  - 27% family member age 65+
- 8% electric heat
- 36% central A/C; 48% room A/C
- 51% electric water heater
- 85% electric dryer
- 82% electric range
- 83% use a dehumidifier

Participants have a good understanding of the plan



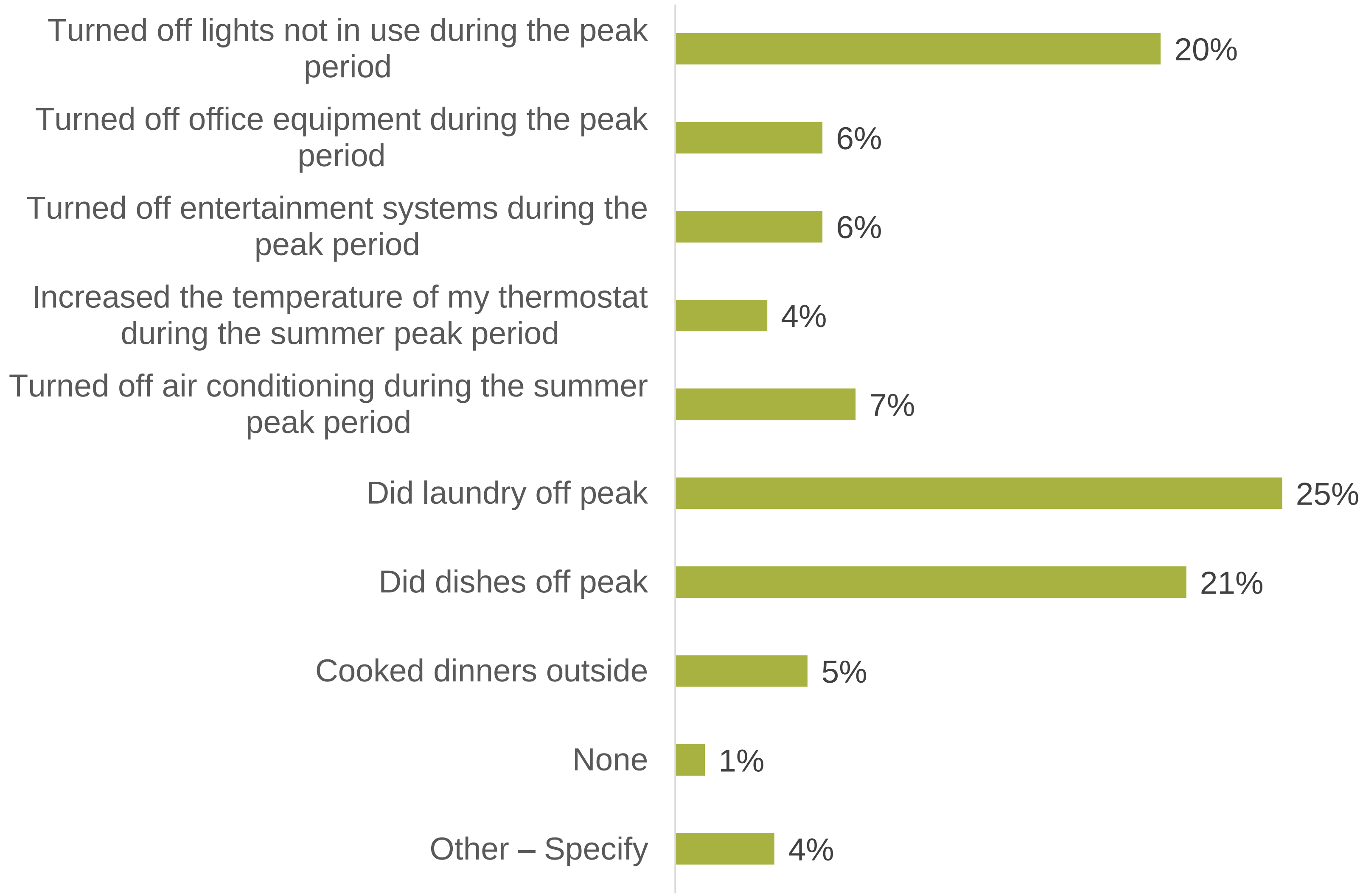
(2016 and 2018 surveys)

Most take steps to reduce consumption



(2015 post-event surveys)

Reported actions taken during CPP events



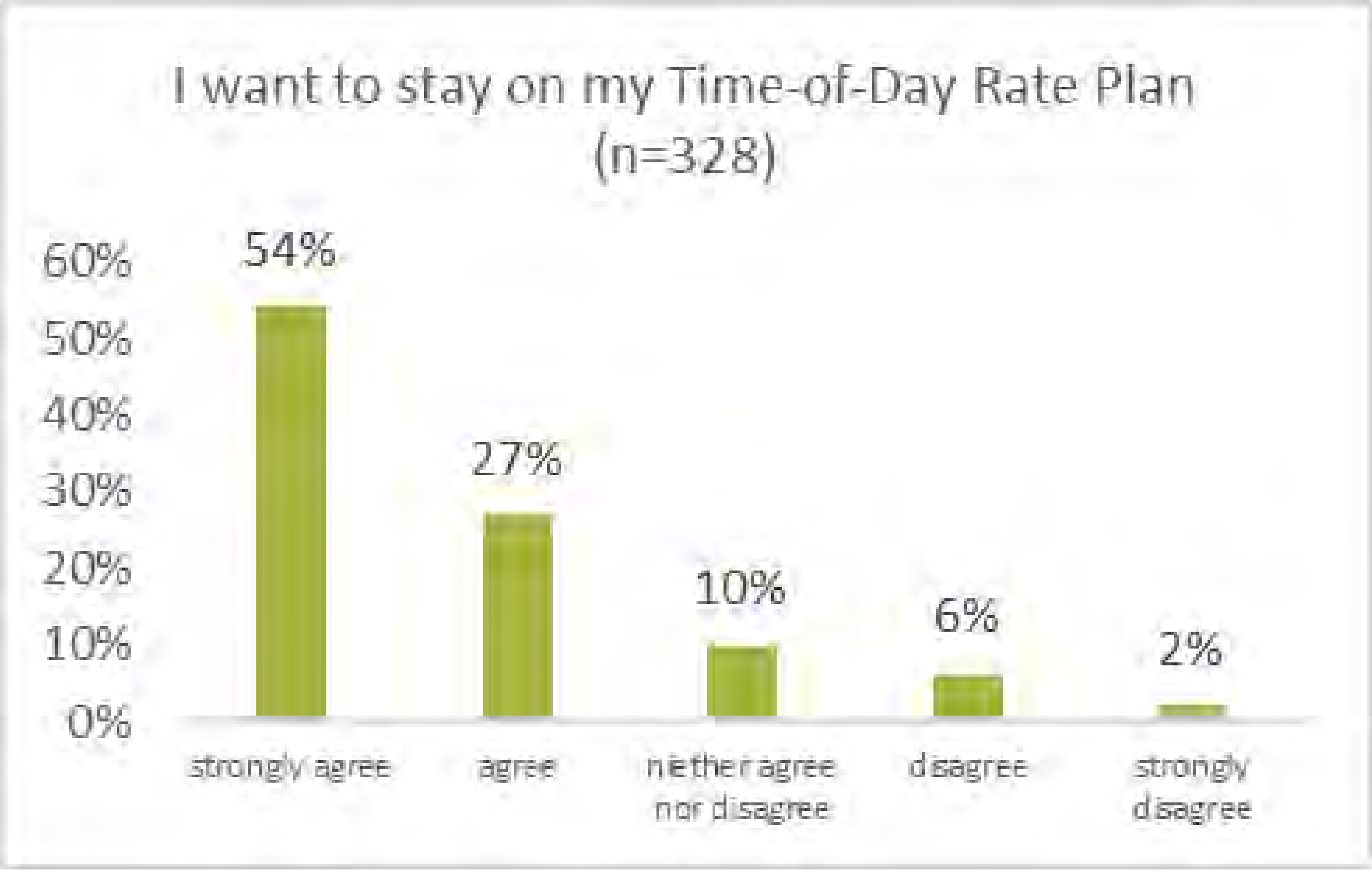
(2018 survey)

Some people took significant steps…

- Summer
  - “Hid in the dark. It was hot.”
  - “It was hot so I napped on the front porch for the entire period. No phone, no lights, no electrical devices, not a single luxury.”
  - “Shut off everything but refrigeration.”
- Winter
  - “No electricity for making dinner.”
  - “Did not cook, including stove, oven, microwave, etc.”

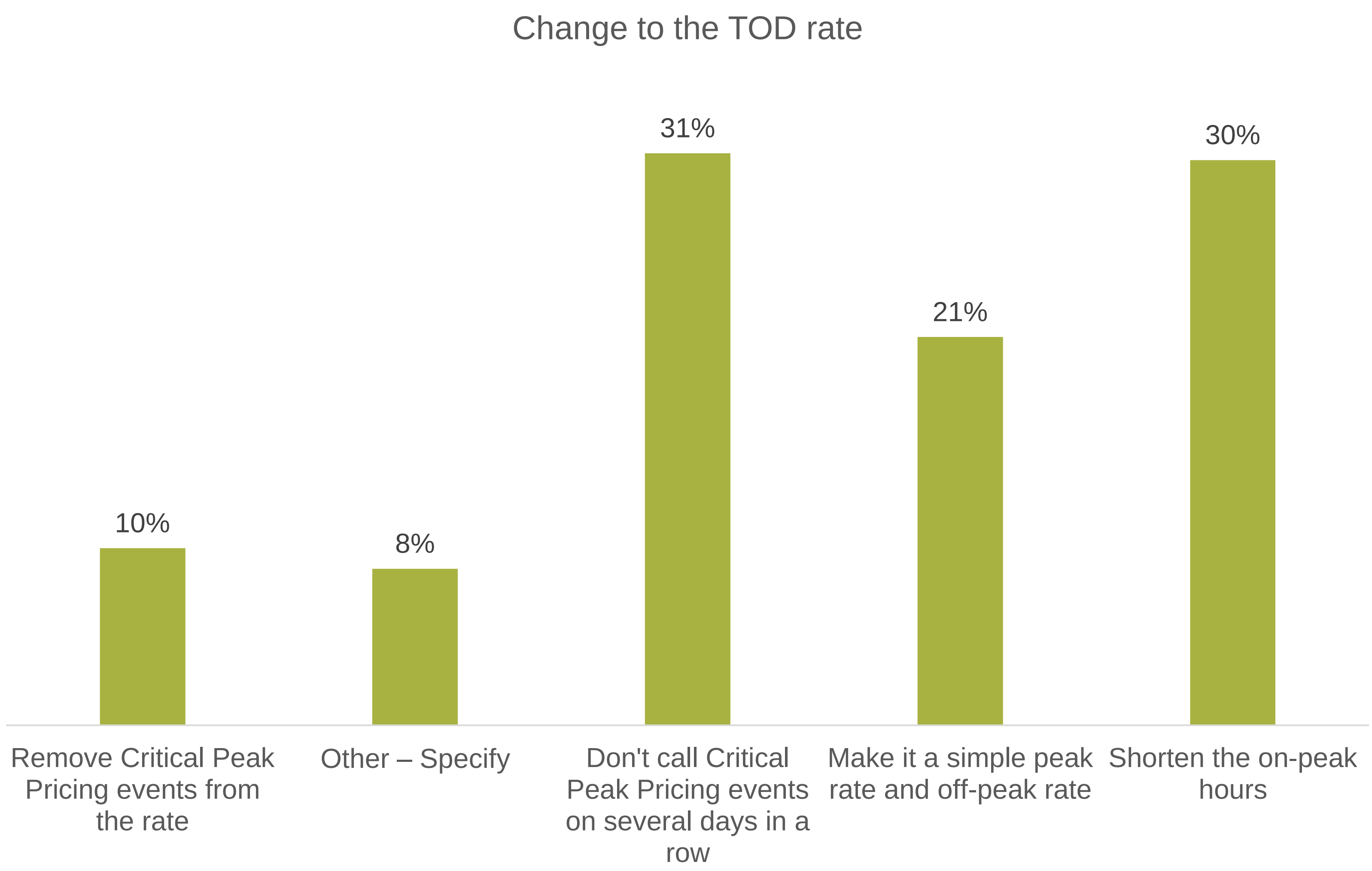
(2015 post-event surveys)

Most are happy with the rate



2016 survey

Suggested changes to the TOD rate



(2018 survey)

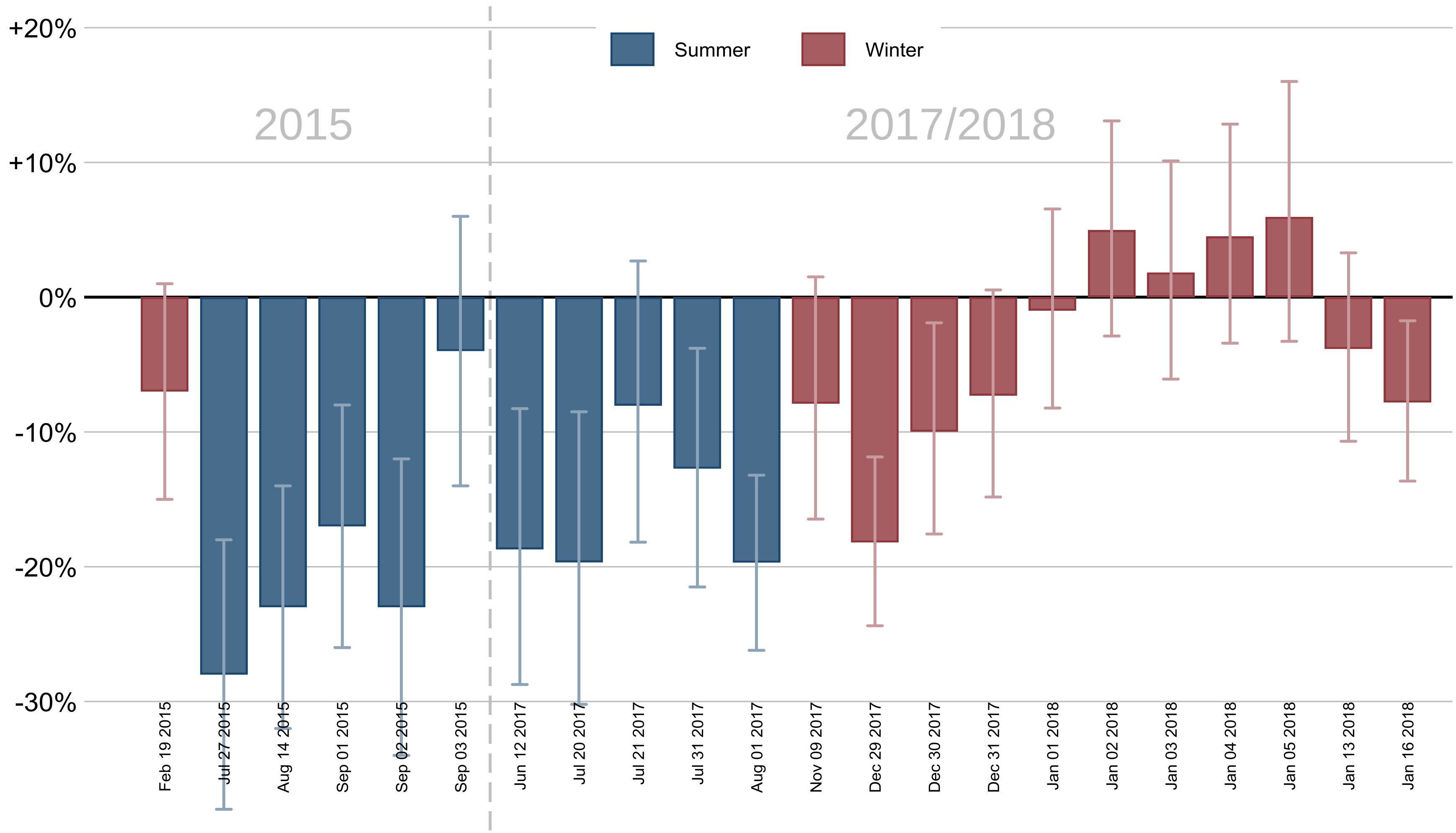
Method for Estimating Load Impacts

1. Match each event day with a “proxy” day with similar weather
2. For each hour of the day, calculate difference in mean load between event day and proxy day
3. Do the same for a group of non-participants, weighted to match participant usage profile
4. Calculate net hourly impact as mean Participant Δ minus Non-participant Δ

Load impact results

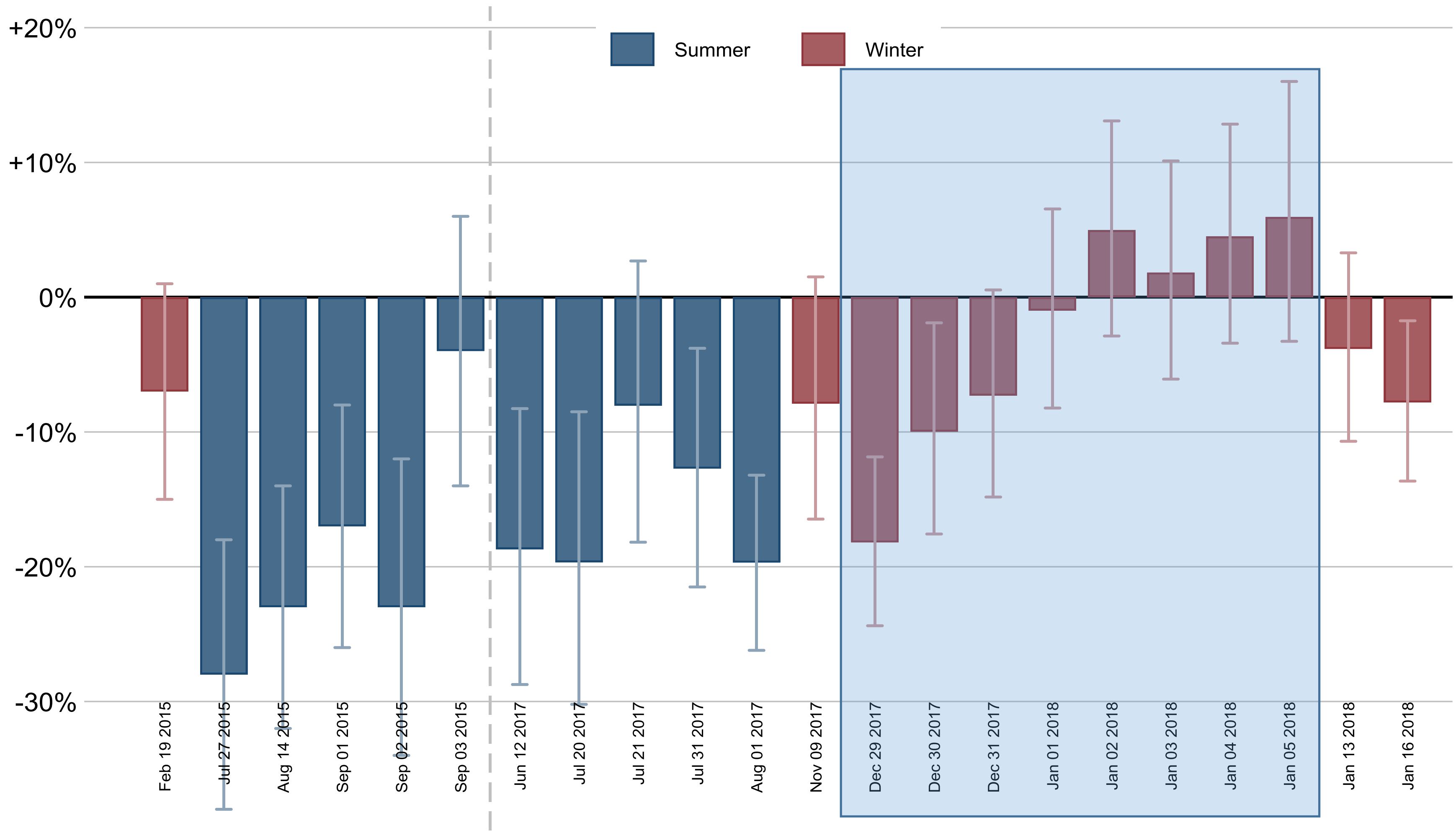
Season	Events	Mean change in load during event	
		watts per customer	Percent
Summer	10	-153	-17%
Winter	12	-67	-4%

Load Impact by Event



(Vertical lines are 95% confidence intervals)

8 Straight Days of Winter Events



(Vertical lines are 95% confidence intervals)

Summary

- Vast majority of participants understand the rate
- Most take action during CPP events
- Summer load impacts > winter impacts
- Evidence of customer fatigue from multiple events in a row

Minnesota Power Time-of-Day Stakeholder Engagement

Meeting 2: September 28th, 2018

Detailed Notes

Contents

I. Discussion of Objectives and Design Principles

1. **The goal is that we are driving towards a program, not a pilot.**
2. **The goal is for time-of-use rates to be available to as many customers as possible - so long as the numbers pencil out in terms of cost-effectiveness.**
    a. AMI has benefits outside of a time-of-use rate, so it would be important to include what the benefits are outside of the time-of-use rate, when analyzing cost-effectiveness. However, it is difficult to quantify some benefits (including customer satisfaction and some other benefits).
3. **MP is deploying AMI through its capital budget and not seeking special cost-recovery. It will be rolled into a rate case as a capital expense**.
    a. MP is putting in AMI as the old meters are replaced.
4. **MP is a winter peaking utility, but the summer peak cost is very close to the winter peak.**

a. MP has a significant number of customers who use electric heating infrastructure and it will be important to consider that in determining whether those customers should be eligible for the TOD rate.
    i. Dual fuel customers have a special rate and are interruptible in the case of a peak event. It is an open question whether those customers could be or should be included in the TOD rate. 13-14% of customers are on the dual fuel rate.

b. Typically, TOD rates have exclusions for certain customers – it depends on the billing system and other rate structures that exist.

c. Exemptions can be limited to certain phases of the program.

II. Presentation: System Load Characteristics (Lon Huber)

1. **Minnesota Power has a very unique electric system.**
    a. Includes 74% industrial load
    b. The load is relatively flat over the year – average gross load is 89% of peak gross load. A typical ratio would be closer to 50%
    c. Net load (gross load minus wind and solar) is also relatively flat
    d. Average residential load is 51% of peak residential load
    e. Winter peaking is caused by electric heating and electric supplemental heating as well as a low penetration of AC (which keeps summer peak relatively low)
    f. 40% of MP's residential customers are in the city of Duluth
    g. Residential load makes up less than 10% of gross load
    h. 2017 MP System Peak is at hour 18 (6pm), while 2013 residential peak was at hour 20 (8pm). 2013 is the most recent year with vetted data.
    i. MP has a fairly stable load over the peak day (net load)
2. **Wind can make it difficult to forecast net peak load timing**
3. **MP's latest IRP determines the underlying assumption of the resource mix for Navigant's analysis**
    a. Assumed 4% peak growth from 2020 to 2030 overall
    b. Assumed 7% peak growth from 2020 to 2030 for residential
4. **MP has no peaking resource – what comes online at peak? What's driving peak costs?**
    a. MISO prices are highest on summer afternoons and winter evenings
    b. Navigant provided indicative marginal costs: a check on the marginal cost during peak (Based on average marginal cost data)
        i. $ 0.16/kWh
        ii. MP residential block rates range from $0.5-0.8/kWh
    c. Heating is particularly tricky for time-of-use rates

   d. There may be less of a cost benefit through an MP TOD than typical utilities.
      i. But MISO market dictates prices and capacity requirements.
   e. If MP is building to cover peak vs. If MP is building as a hedge for wind intermittency will determine value.

5. **How do we want to look at peak hours for a system with an incredible load profile?**
   a. Could do 12 hours of peak based on the profile.
   b. How to design a capacity focused TOU in this unique system?
   c. Generation fleet is unique too. MP is moderating base plants, not peakers or CTs.
6. **Could CPP help MP address wind intermittency?**
   a. Depends on the accuracy of the forecast. MP provides day-ahead notice for CPP.
   b. Wouldn't be able to give day-ahead notice on a CPP to address wind intermittency.
   c. Does CPP create snap-back issues? Relatively flat load can exaggerate the issues of snap-back.

III. Presentation: CPP Findings from the Smart Grid Pilot (Scott Pigg)

1. **Analysis context:**
   a. MP's current CPP has a 3 hour window with day-ahead notice
   b. Looked at 6 events in 2015 and 16 events in 2017/2018
2. **Participant characteristics:**
   a. Mostly single-family home participants
   b. 8% electric heating
   c. 36% central A/C and 48% room A/C
   d. 51% electric water heater
   e. 83% electric dehumidifier
3. **Findings from participant surveys:**
   a. People mostly understood the rate
   b. Most people took action to reduce their electric usage during a CPP event.
      i. Most people reported turning things off that were not in use and doing laundry/dishes during off-peak
      ii. Some people took drastic steps
   c. People were generally happy with their TOD rate
4. **Load Impact Results:**
   a. Got more of a reduction in summer events (1-3pm) than winter (5-8pm)
      i. 17% reduction in summer (153 watts reduction)

        ii. 4% reduction in winter (67 watts reduction)
    b. In 2017/2018 the winter events at times went positive (usage might have increased), but 8 of those events were on consecutive days over the New Year holiday. The first day (1 of 8) of consecutive CPP events had about an 18% reduction, but that reduction waned and disappeared over the subsequent CPP days. Indicates CPP fatigue.

5. **How much did it cost people who didn't reduce usage during CPP events?**
    a. Rate goes up during those windows to $0.77/kWh, so the bill impact can be significant, especially for electric heating and supplemental electric heating
6. **What was the value to MP for the CPP events?**
    a. Very tiny impact to MP. Lost about $10 per customer in the first year of the program, then adjusted the on-peak adder from $0.14 to $0.49.
    b. MP hit cap on hours that they can call a CPP
    c. MP is not decoupled
    d. CPP could impact the amount of money that MP makes depending on how customers respond.
    e. 2016 had no events due to moderate pricing
    f. Determining a CPP is based on cost
        i. Market price related – day-ahead MISO pricing
        ii. MP has discretion on whether to call CPP or not – has internal guidelines for when to call CPP based on market price
7. **Could MP have separate groups of customers in order to avoid CPP fatigue when there are multiple CPP days in a row?**
    a. Hard for customers to know how much they are saving or spending with TOD vs. regular MP rates.

IV. Discussion: Objectives, Design Principles, Roll-out Plan

1. **How will the TOD interact with CARE and Budget Billing?**
    a. Need to follow up on this in subsequent meetings
2. **Designing a TOD Rate for this unique load profile**
    a. May make most sense for MP's TOD to track to MISO market rather than MP's own gen resources. – weighted average Locational Marginal Pricing (LMP)?
    b. Would be difficult to determine when renewables are on the margin for the MISO system -- makes it challenging to meet the objective to design a rate that helps integrate renewables.
3. **What is the best structure to reduce costs in this system?**
    a. Cost causation linkage will be less clear for MP than other utilities given MP's unique profile.

   b. Group is flexible to best way to structure a TOD for MP with full recognition that MP has a very unique system.

4. **Concerns:**
   a. Not all stakeholders can support Part 4 (Deployment Process) of that document
   b. Revenue neutrality is more challenging without a decoupled rate structure. If customers respond to price signals, as intended, the utility may not recover sufficient to stay revenue neutral.

V. Reflection, Wrap-up, and Next Steps

1. Next meetings will be to review the rate design options put together by MP and Navigant.

Minnesota Power Advanced Time of Day Rate

Meeting 3: December 10th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

10:00am – 2:00pm

For remote meeting access, please click this link at the meeting time:
https://betterenergy.zoom.us/j/275325095

Note: for optimal audio quality, we suggest using headphones or a headset

Draft Agenda

10:00-10:10am	Welcome, Intro's
10:10-10:30am	Review and Discuss Prioritized Design Principles
10:30-11:00am	Presentation on Feedback from MN Power Customer Workshops
11:00-12:00pm	Presentation on MN Power's Draft TOD Recommendations
12:00-12:30pm	BREAK- Grab Lunch
12:30-1:45pm	Discussion: • What are the strengths of the recommendations? • What improvements could be made to the recommendations? • How well do the draft recommendations align to the design principles? (and/or are there suggested changes to the design principles?) • What, if anything, would cause you to oppose the package of recommendations as a whole? • What additional information would be necessary to evaluate the recommendations?
1:45-2:00pm	Reflection, Wrap-up, and Next Steps
2:00pm	ADJOURN

Customer Insights from Online Energy Survey

minnesota power

AN ALLETE COMPANY

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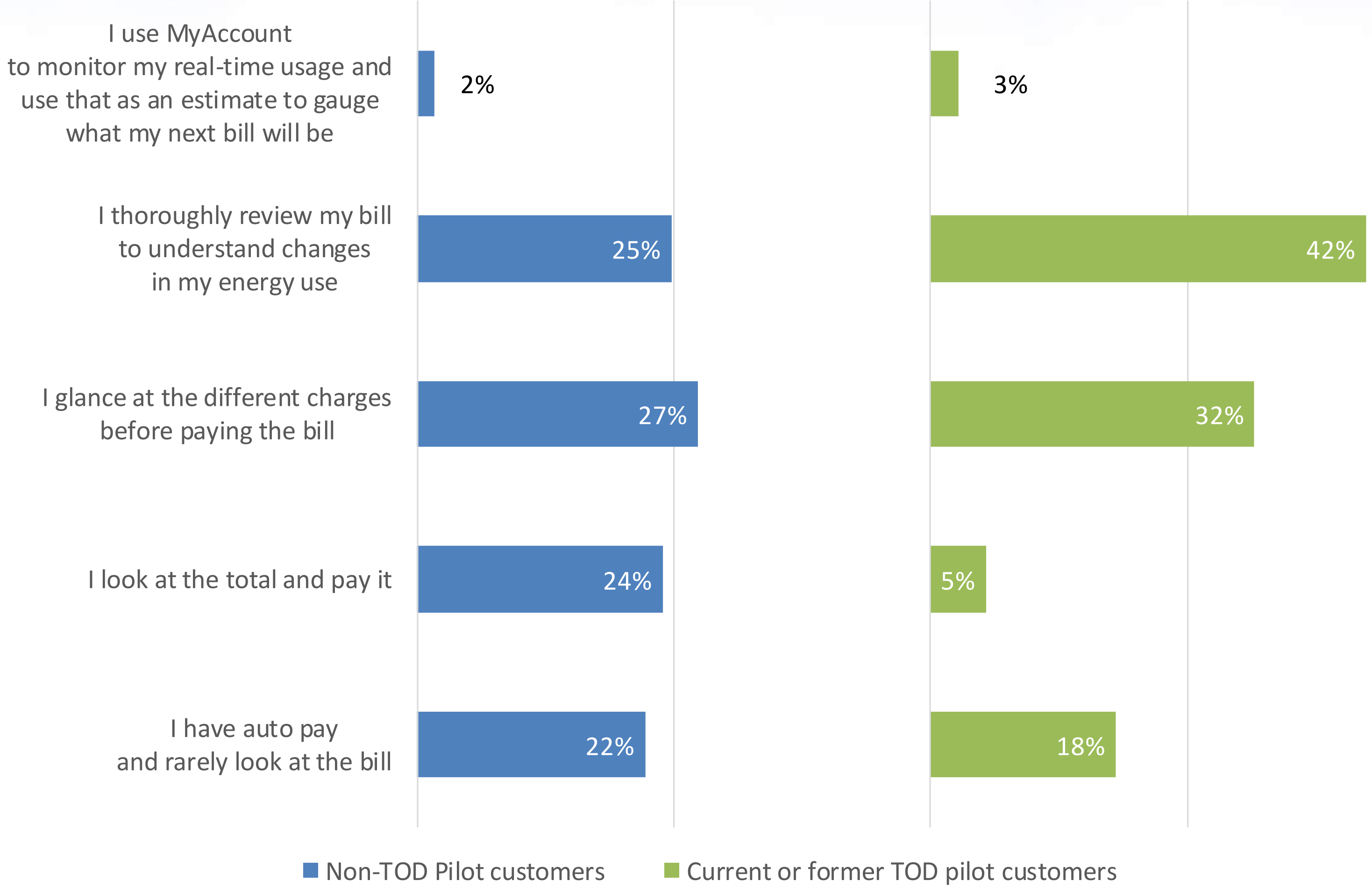
Overview

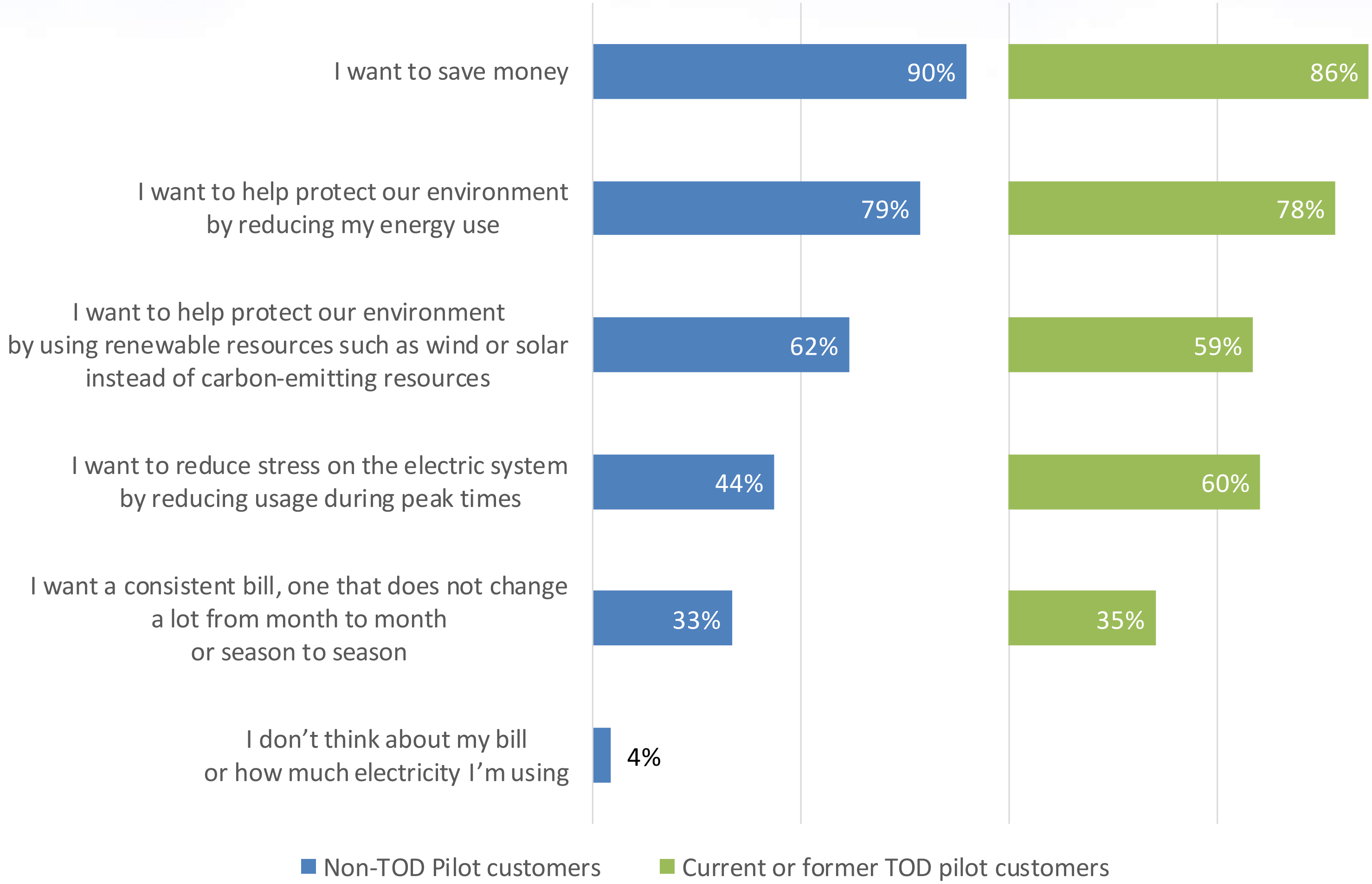
- In October of 2018 an online survey from Minnesota Power was promoted to customers through various digital channels (social media, Time-of-Day Rate Pilot past and present participants direct emails, known Electric Vehicle owner emails)
- Dates: 10/17/18 – 11/5/18
- Responses: 229 (1 Partial) – 111 with a connection to the TOD pilot
- Limitations: online only, potentially biased based on how it was conducted and who we were able to "direct market" it to

TOD customers are interested in the details of their bill



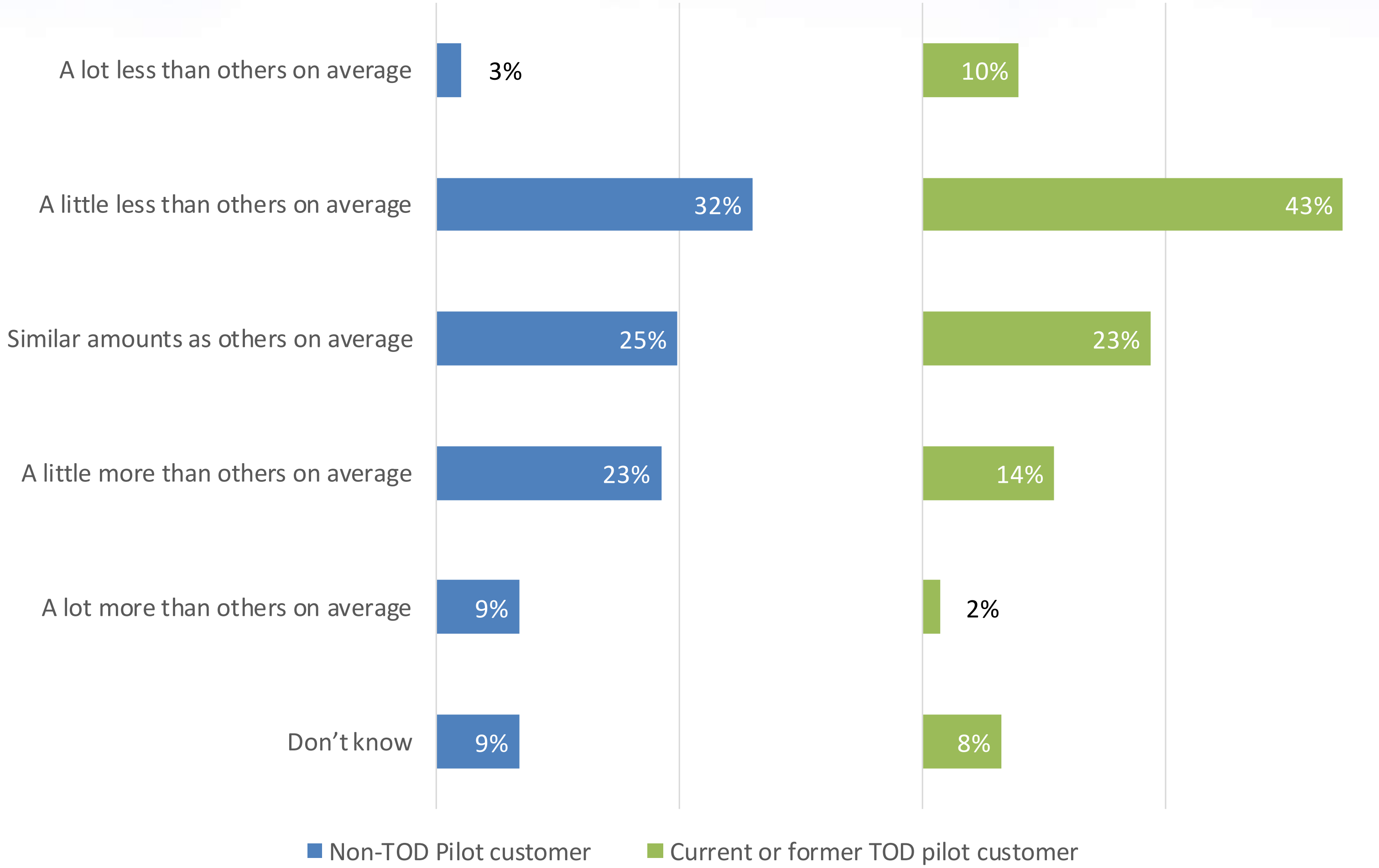
Q: Which of the following statements most closely describes how you handle your monthly electric bill?

The most important factor for customer participation in a TOU program is saving money



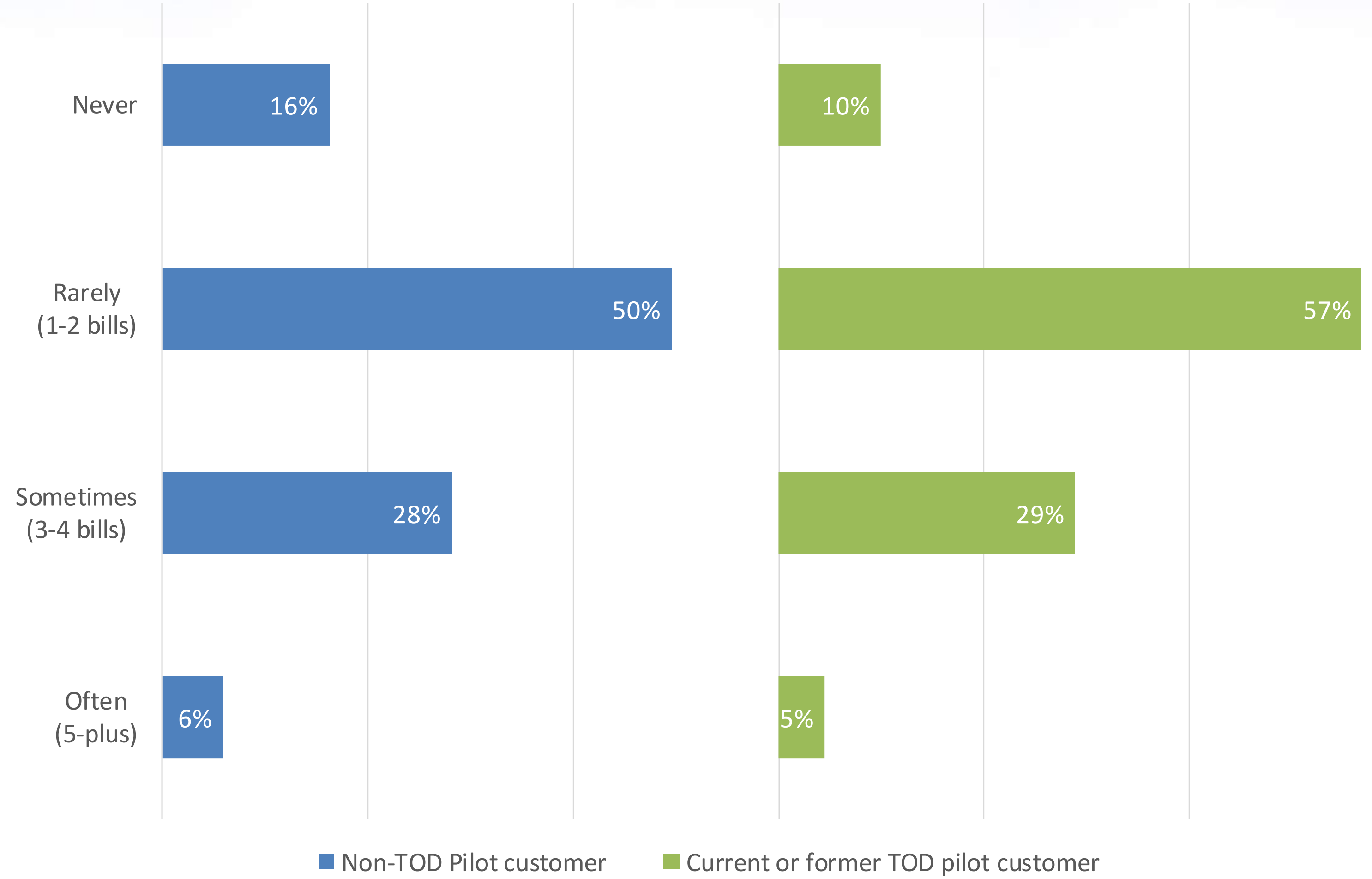
Q: Please select all statements that apply to you:

Approximately 60% of customers feel they use similar or less amounts of energy when compared to others



Q: When you think about the amount of electricity you use every month, do you think you are using:

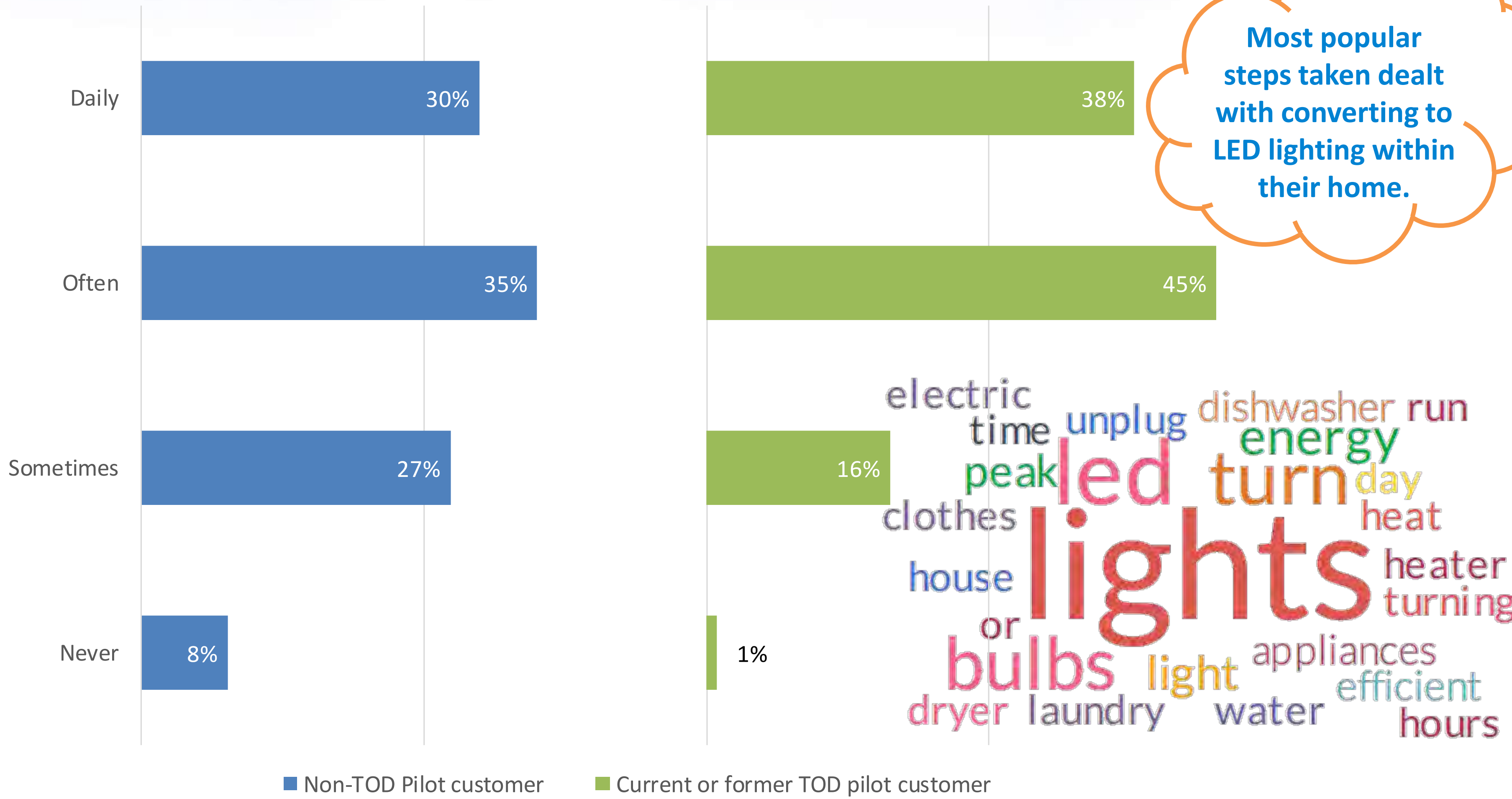
Approximately 85% of customers have received a higher than expected bill within the last year



Q: In the past 12 months, how often did you receive an electric bill that was higher than you expected?

Most customers feel they have taken steps to reduce their bill within the past five years

Most popular steps taken dealt with converting to LED lighting within their home.



Q: In the past five years, have you taken steps to lower your electric bill by using less electricity?

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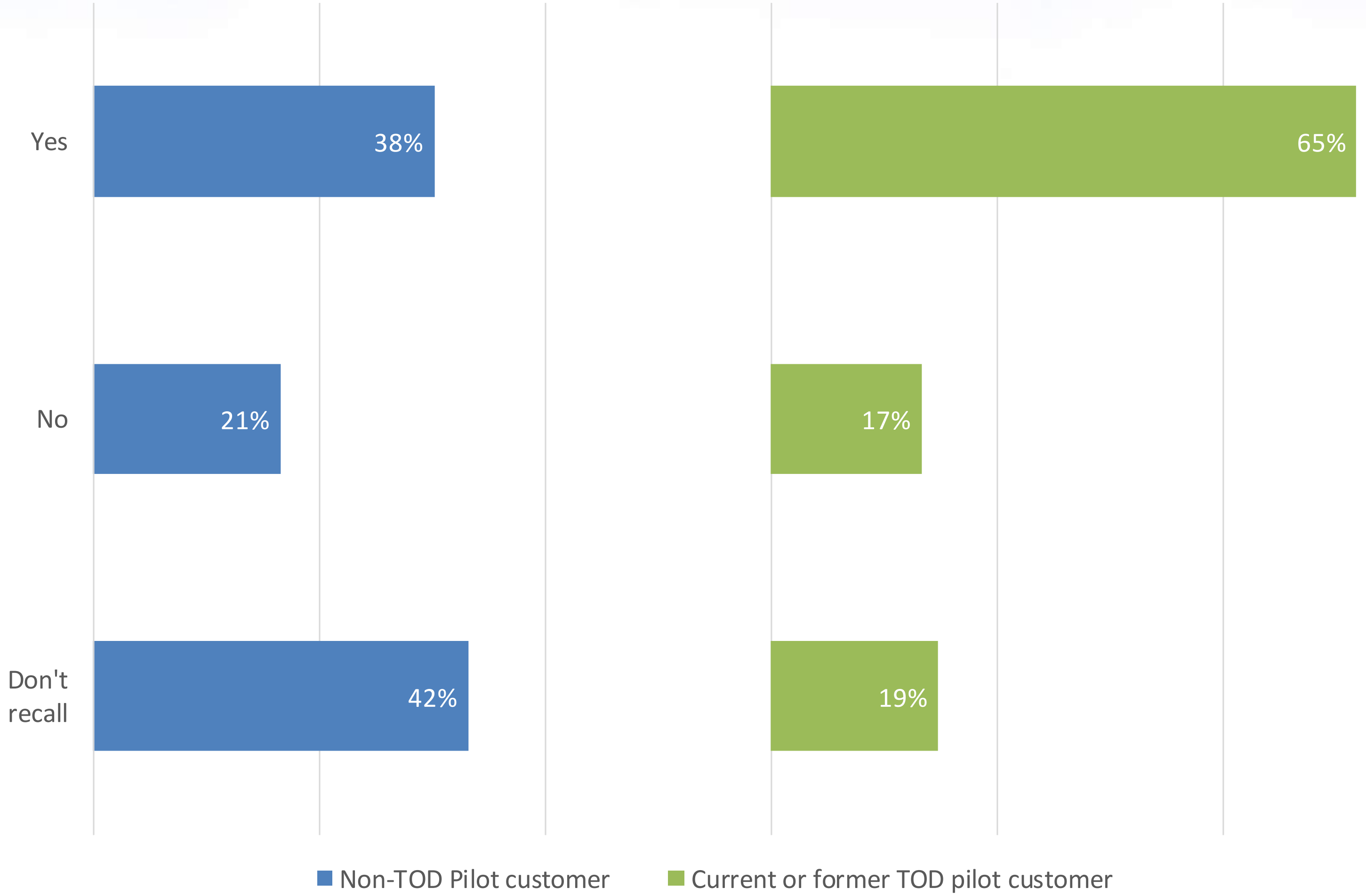
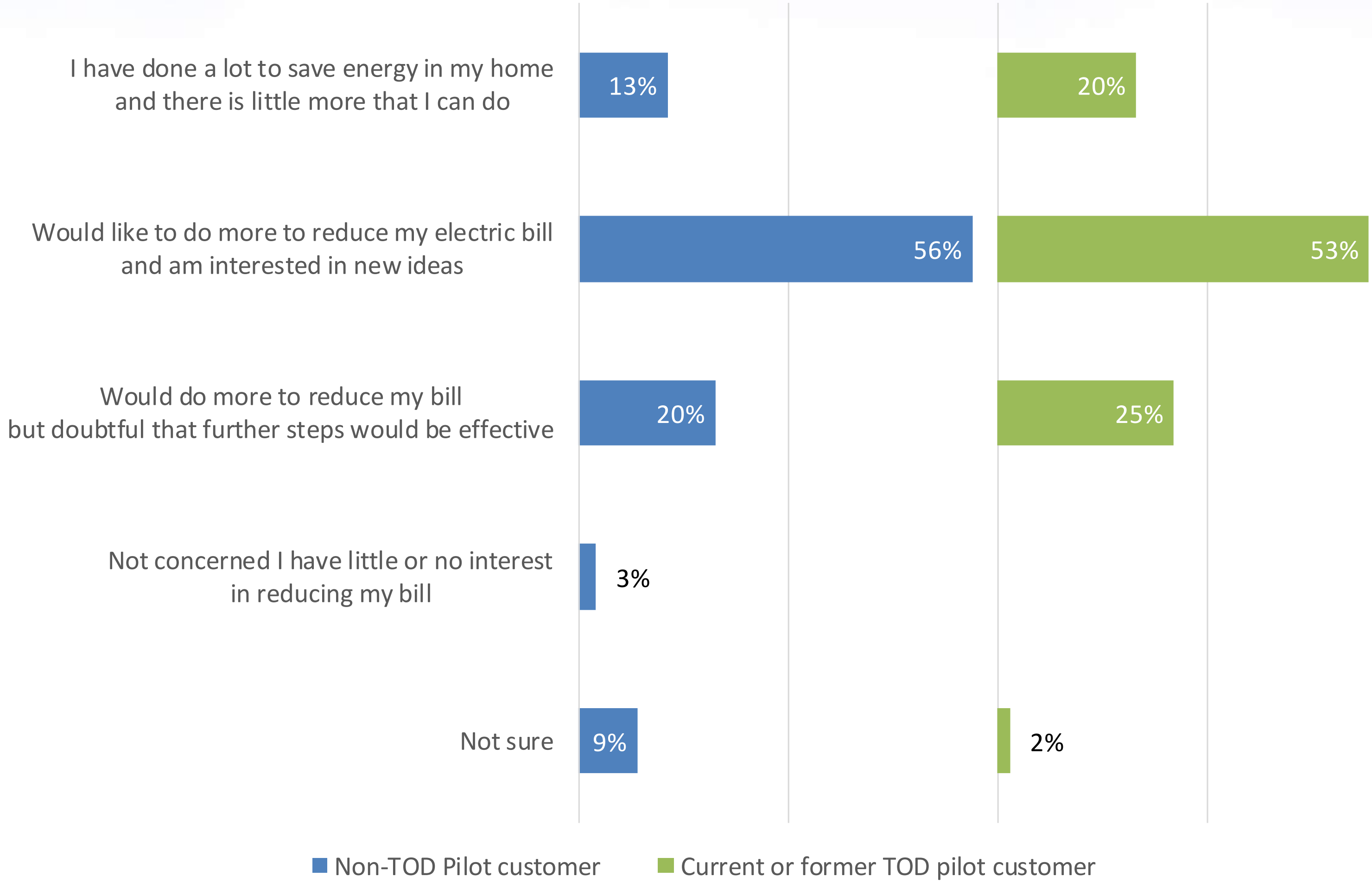
For TOD customers that have taken steps to reduce their bill, 65% saw results



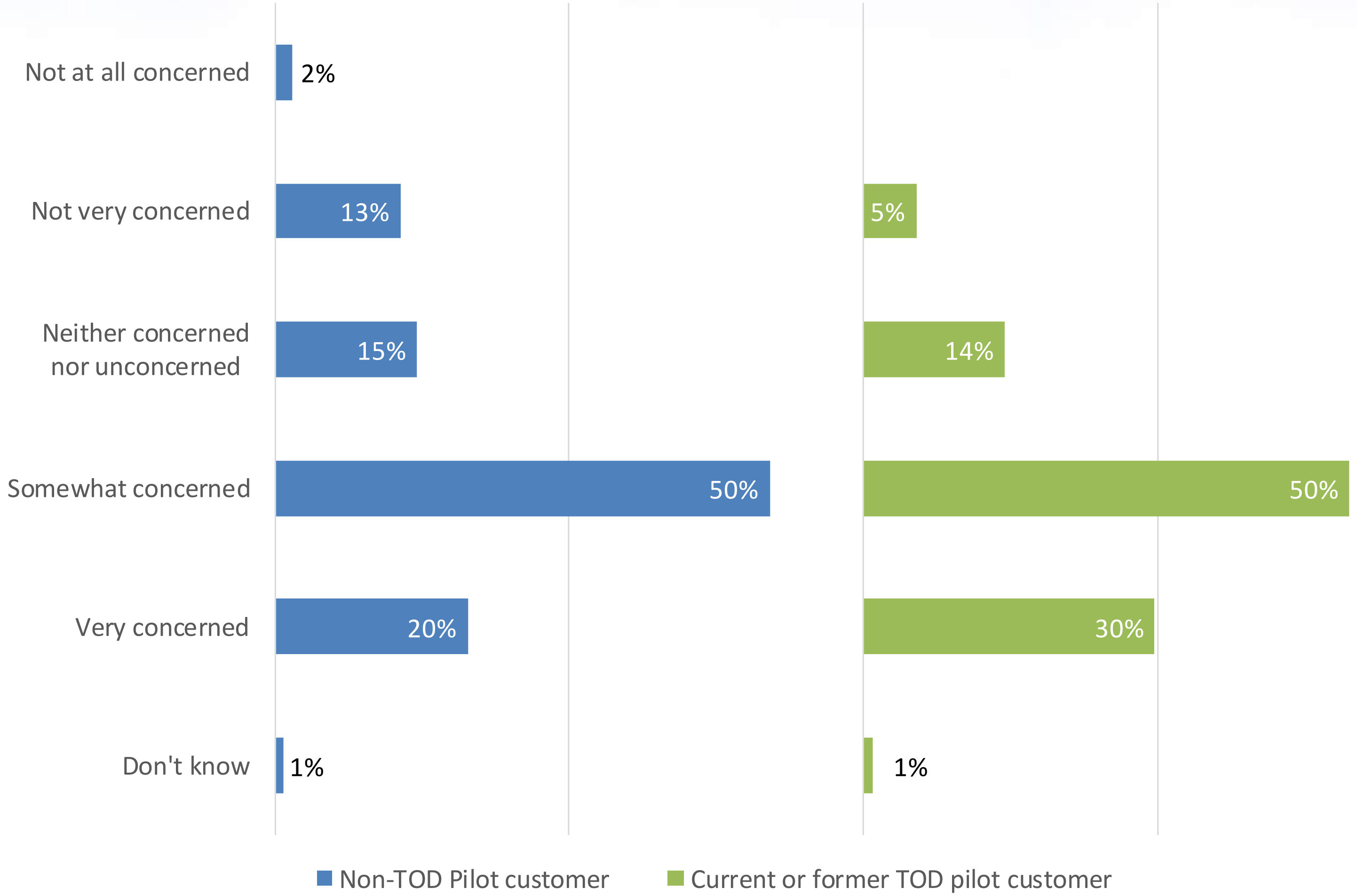
Q: Did you notice any reductions in your electric bill after taking these steps?

The majority of customers would like to do more, but some don’t think there is more they can do



Q: Which of the following statements best describes your current attitude toward reducing your electric bill?

Almost ¾ of customers have concerns about the cost of their electricity in the next five years



Q: Looking ahead five years, how concerned are you about the cost of electricity?

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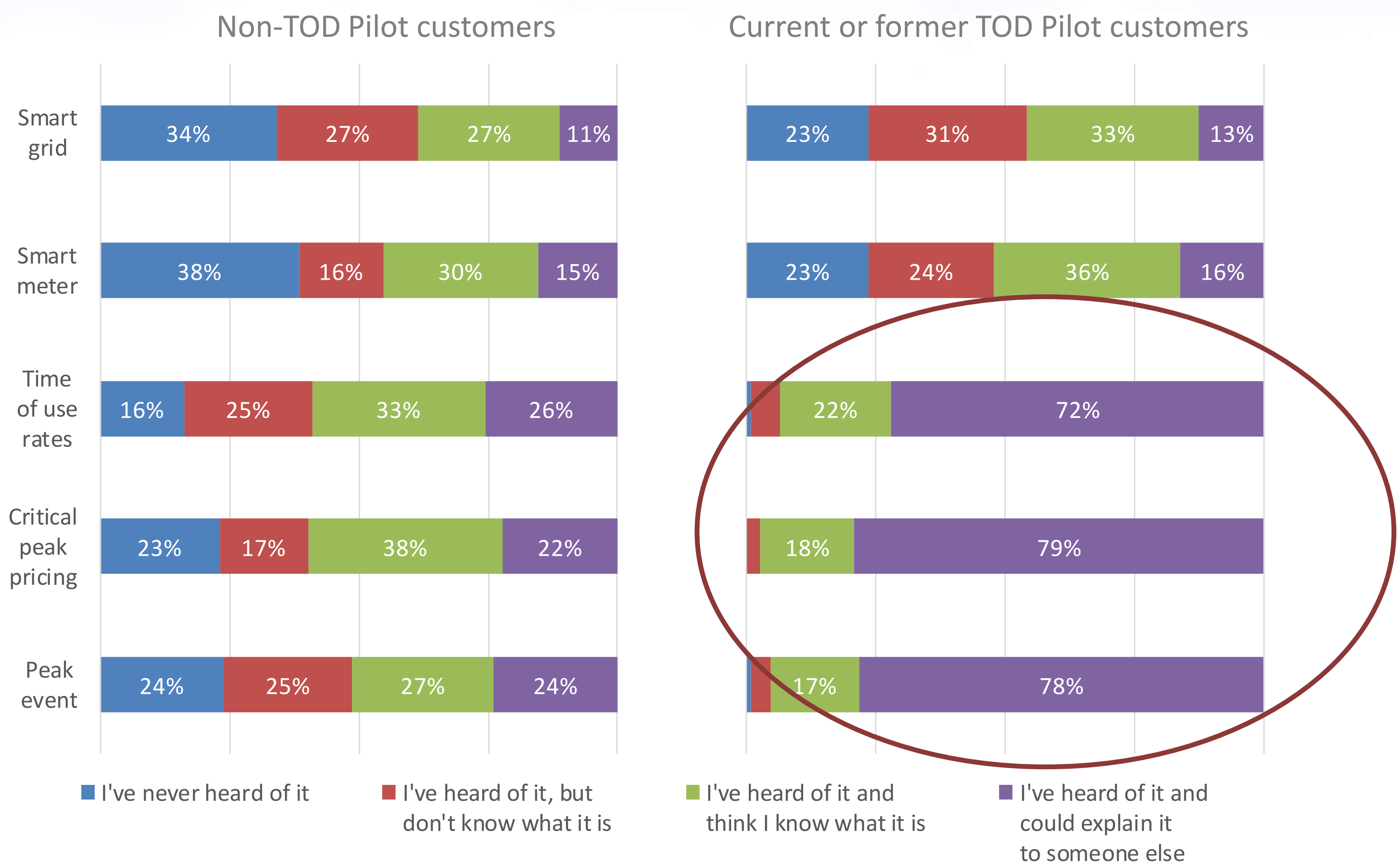
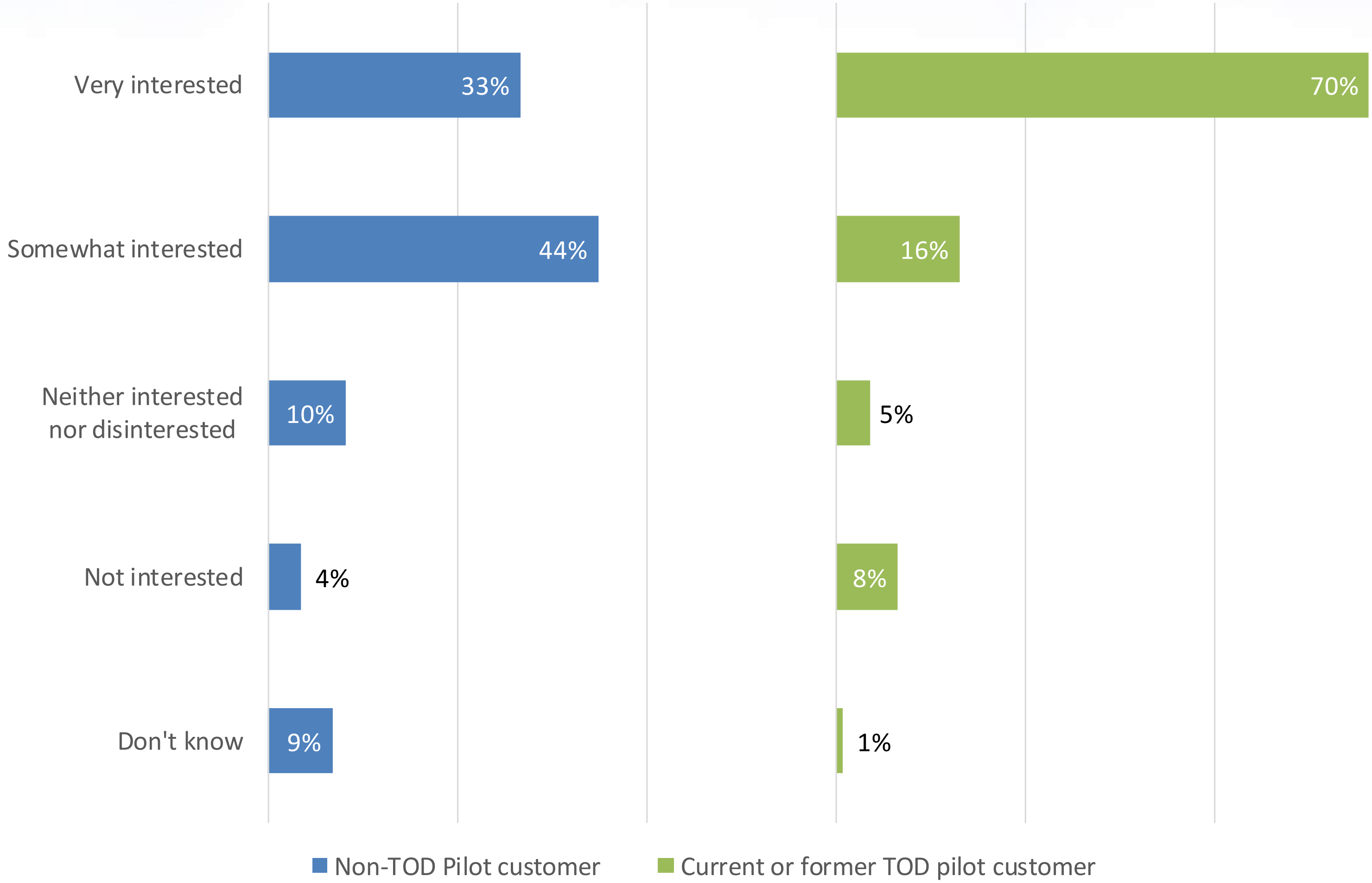
Most customers are aware of terms surrounding TOU rates, but level of understanding varies



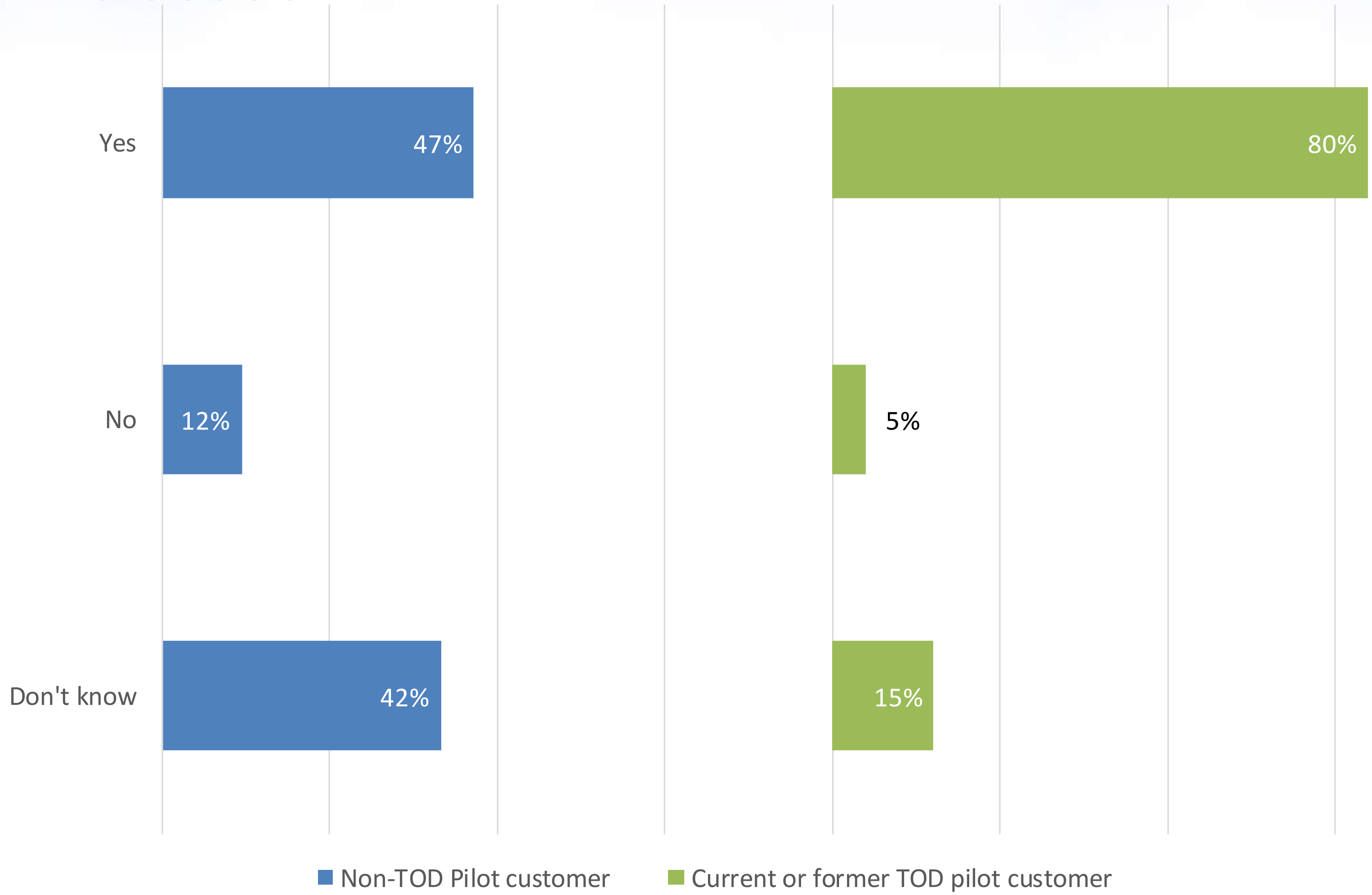
Q: How well do you understand the following energy-related terms?

The majority of customers are interested in a Time-of-Day rate if it can save them money



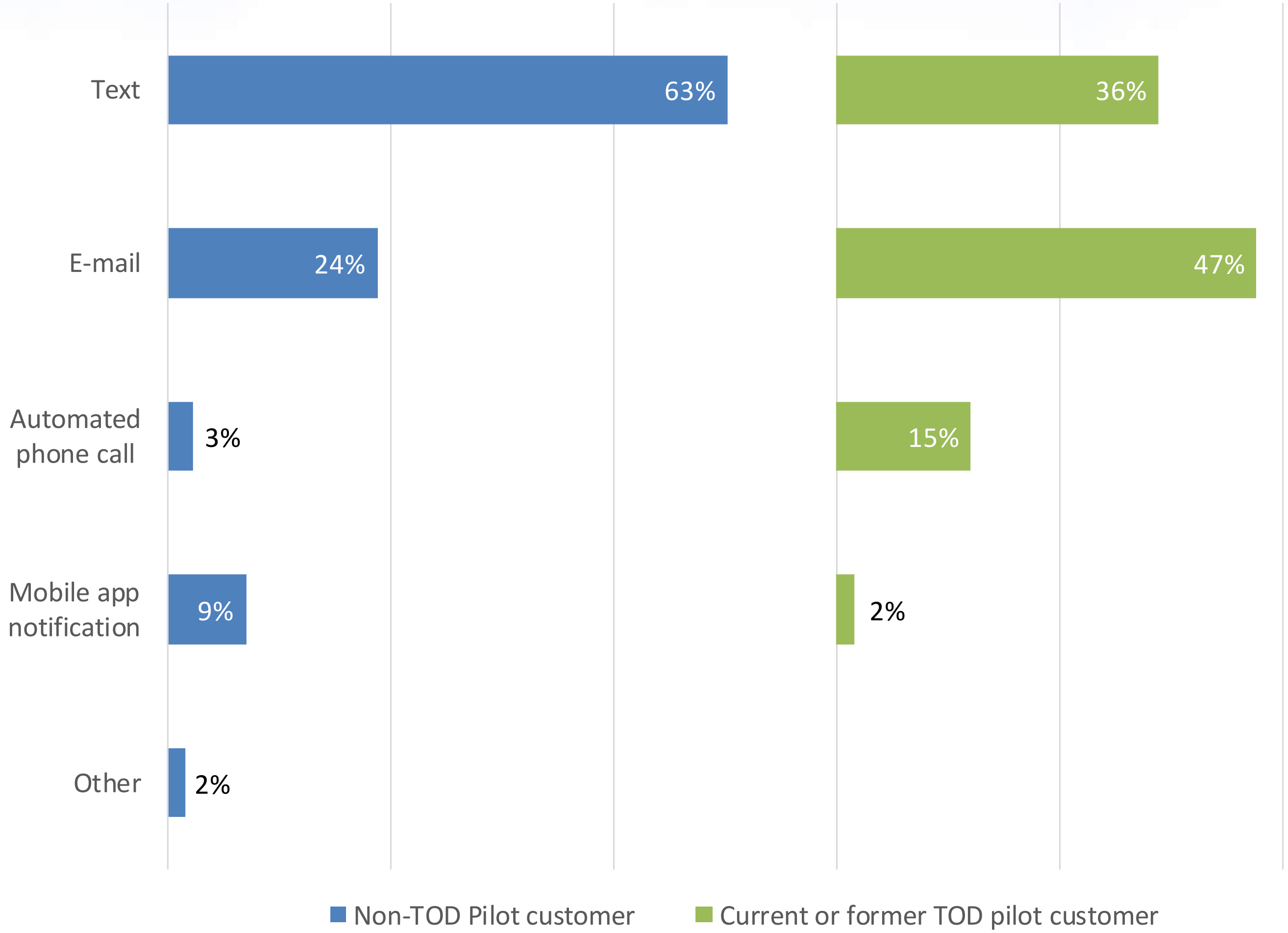
Q: How interested would you be in an optional Minnesota Power time-of-day rate that could help you save money by shifting some of your energy usage to off-peak times like nights and weekends?

Almost half of non-TOD customers and 80% of TOD customers feel they could shift their energy use from season to season



Q: The hours for peak electricity use change from season to season (e.g., winter on-peak is 5-9 p.m., summer on-peak is noon-4 p.m.). If you were on a time-of-day rate, would you be able to shift your energy use each season?

Customers prefer to receive alerts via text or email



Q: What would be your preferred method of communication if you were on a time-of-day rate and Minnesota Power could alert you to an upcoming peak event and provide tips to reduce your bill?

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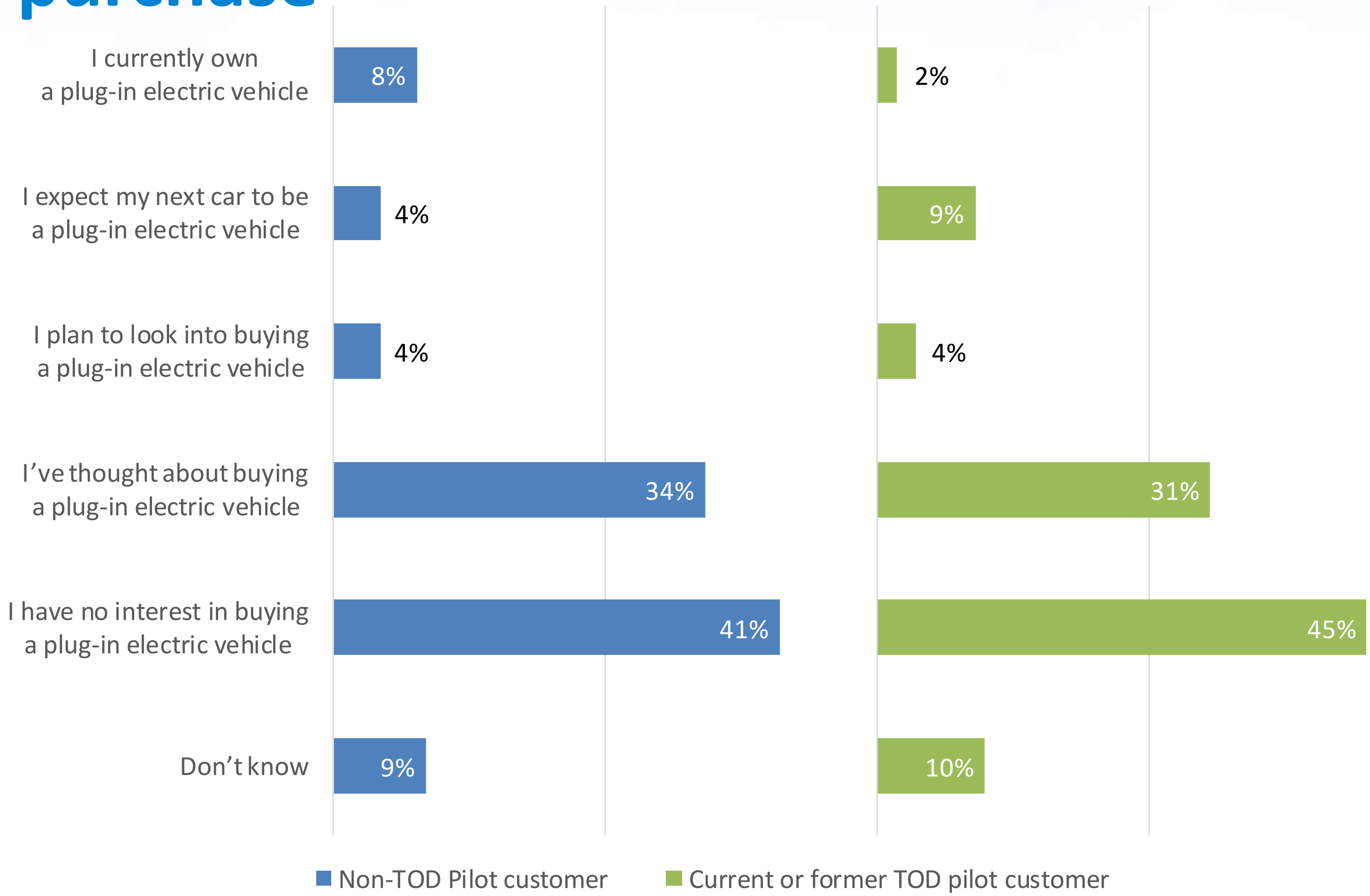
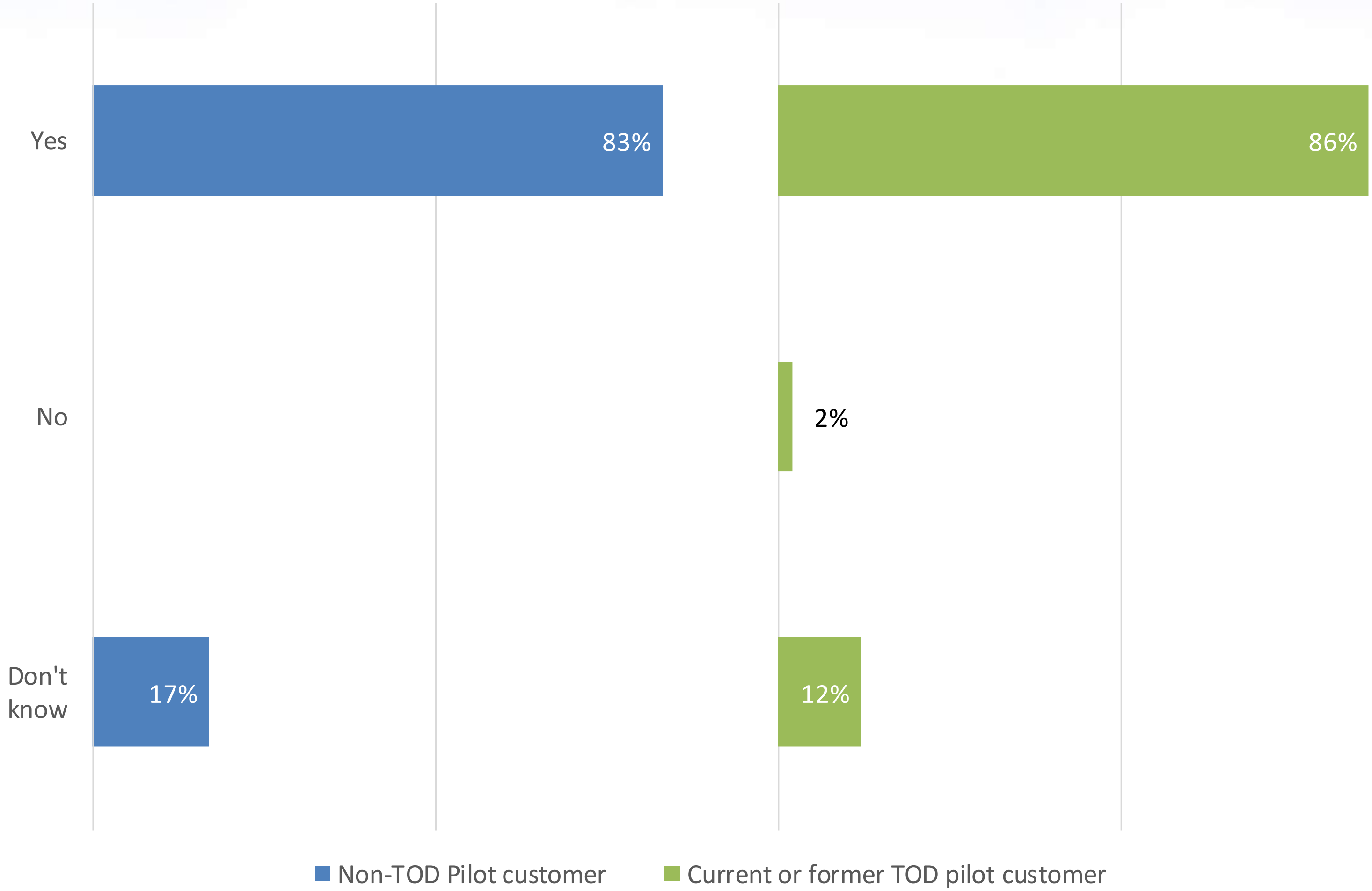
Over 10% of respondents currently own or expect to purchase a PEV, over 30% have considered a PEV purchase



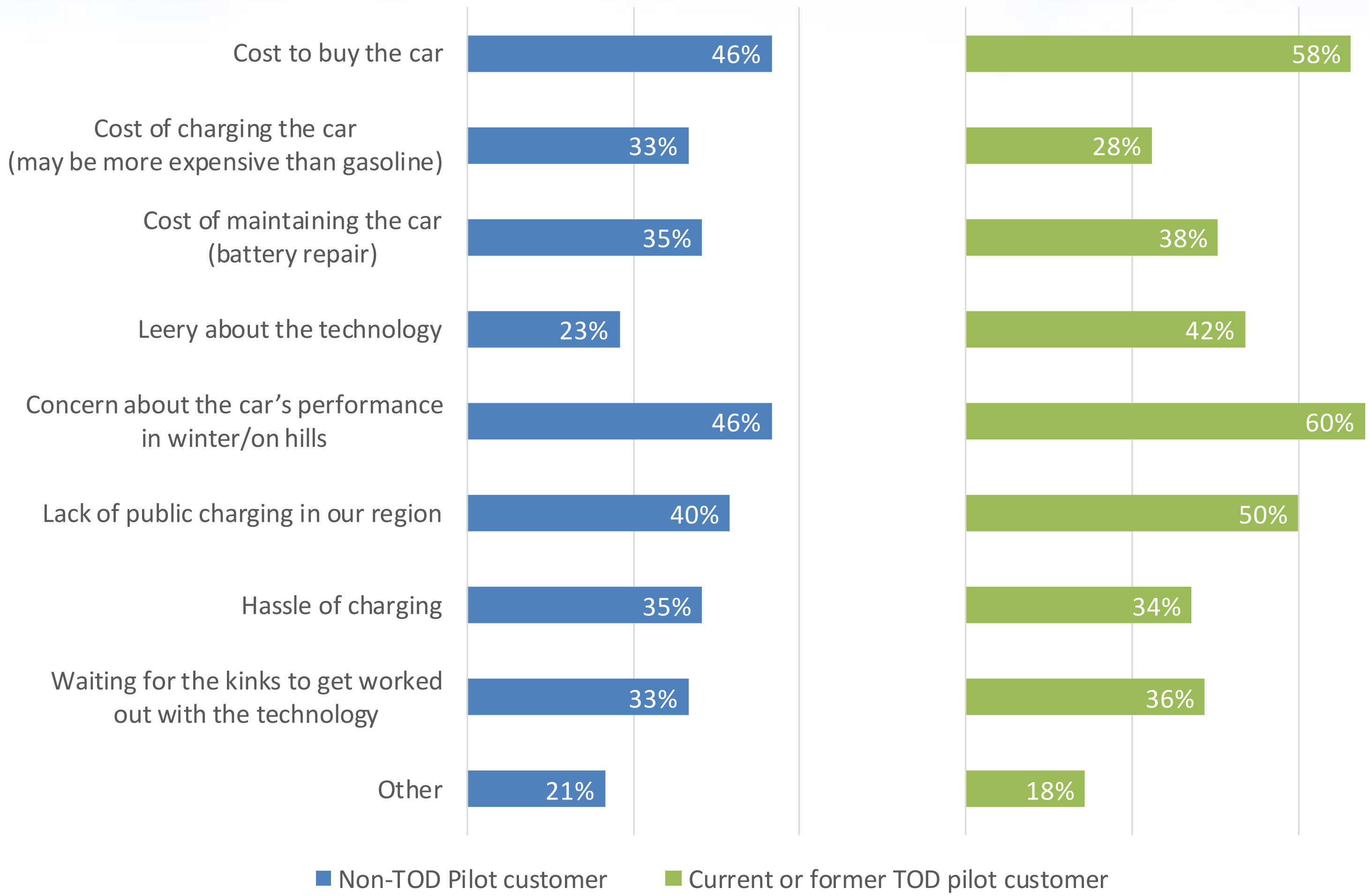
Q: Which of the following statements best describes your interest in a plug-in electric vehicle?

A large majority showed interest in TOU rates as a way to save money on PEV charging



Q: If I owned a plug-in electric vehicle, I would be interested in having my household on a time-of-use rate to save money on my charging costs by charging the vehicle during off-peak times.

Cost and performance are top reasons for customers to not be interested in PEV



Q: Why aren't you interested in purchasing a plug-in electric vehicle? [select all that apply]:

Survey Response Demographics

- Home Owners vs. Renter
  - Home Owners **93% |** Renters **7%**
- Participants by age range:
  - 18 – 34 **17% |** 35 – 54 **42.4% |** 55 – 65 **25.3% |** 65+ **14.4% |** Prefer Not to Answer <**1%**
- Employment Status:
  - Working: **80.3% |** Retired: **16.2% |** Not Working: **1.7% |** Prefer Not to Answer: **1.7%**
- Children in the Home:
  - Yes **33.8%** |No **67.2%**
- Annual Household Income:
  - <$35K **6.6% |** $35K – 75K **36.7% |** $75K+ **45.9% |** Prefer Not to Answer **10.9%**
- Gender:
  - Male **41.9% |** Female **54.1% |** Prefer Not to Answer **3.9%**
- Location:
  - Greater Duluth **~90% |** Other: ~**10%**
- Current/Past MN Power Time-of-Day Participants
  - **111**

TOU RATE OPTIONS FOR MINNESOTA POWER

LON HUBER

12/10/2018

COST ALLOCATION OPTIONS

Option A: allocation of embedded costs using load duration method

- Allocates embedded costs across time periods based on the load that caused these costs
- (further detail on next slides)

Option B: no allocation of embedded costs

- Treats embedded costs as sunk costs
- Generation and network capacity have already been built
- Future consumption decisions cannot reduce these embedded costs, so costs recovered evenly across all time periods
- (provides a short-run view of marginal cost of service: only LMPs are marginal, all other costs are sunk)

Option C: LMP allocation approach

- Allocates embedded costs across time periods based on LMPs, as these are a readily available and reasonable proxy for load

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COST ALLOCATION OPTIONS – DETAIL

MP's annual residential cost to serve is broken down by component and allocated across 8,760 hours

2018 costs		Option A: Embedded cost allocation Allocated to each hour using:		Rationale	Option B: No embedded cost allocation. Allocated to each hour using:	Rationale	Option C: LMP allocation approach Allocated to each hour using:	Rationale
Capacity	$47m	Generation capacity	MISO load	MP's generation capacity requirements (imposed by MISO) are driven by its load during summer afternoons when MISO load peaks	Allocated evenly	Costs are sunk, only marginal costs are allocated	MISO LMP (energy price) at MP node	LMPs include generation and transmission cost signals, and are a reasonable proxy for distribution cost signals also
		Transmission capacity	Minnesota Power gross load	Gross load drives the capacity requirements (and thus cost) of MP's transmission system				
		Distribution capacity	Minnesota Power residential load	Residential peak demand is the key driver of the capacity (and thus cost) of the distribution system in residential areas				
Energy	$31m	MISO LMP (energy price) at MP node		The LMP represents the cost to Minnesota Power of supplying energy to its ratepayers, either through self-generation or purchases through MISO	(as Option A)		(as Option A)	
Customer	$27m	Allocated evenly		These costs (e.g. metering, customer services) do not vary with load so are recovered in part through the monthly Service Charge with remainder shared evenly across all hours	(as Option A)		(as Option A)	

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PEAK PERIOD OPTIONS

Option 1: Targeted peak periods

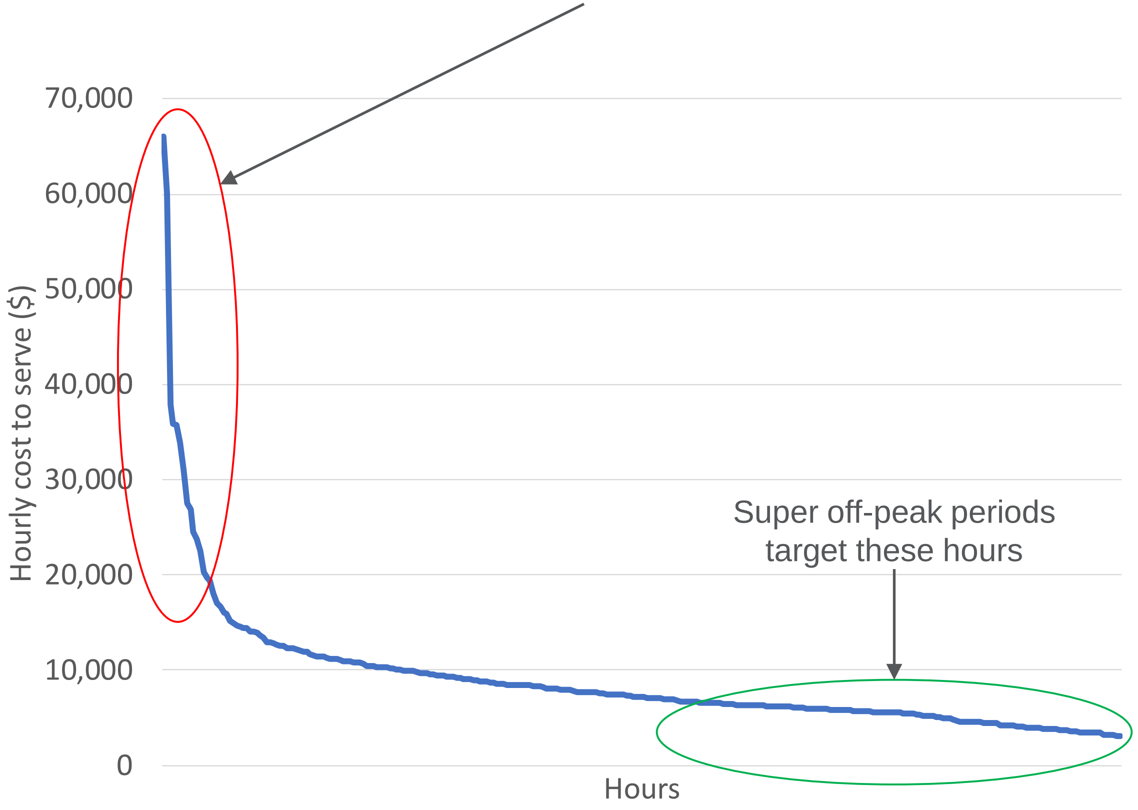
- Allow peak period times to vary by season
- Allow shoulder months with no peak periods

Option 2: Consistent peak periods

- Maintain consistent peak period hours across the year

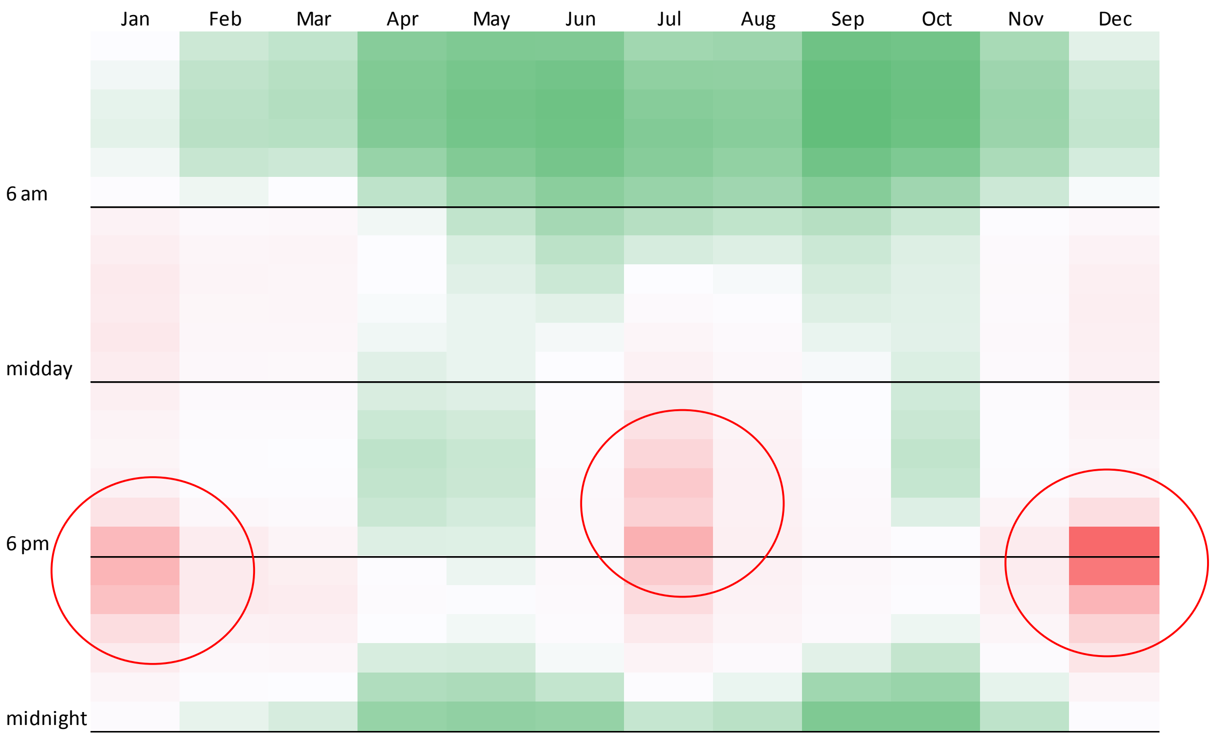
COST TO SERVE BY HOUR

A small number of hours per year have very high cost to serve; peak prices will target these hours



Cost to serve chart shown based on cost allocation option A

Highest cost to serve hours occur winter evenings and summer afternoons



Red = highest cost to serve, **Green** = lowest cost to serve

DETERMINING PEAK TIME PERIODS – OPTION 1 TARGETED PEAKS

We compared the cost to serve load in each hour with the average cost to serve load

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

162% above average (i.e. more than double) cost to serve during winter peak

136% above average (i.e. more than double) cost to serve during summer peak

Red = highest cost to serve, **Green** = lowest cost to serve

- Clear **seasonal pattern** in cost to serve
  - Apr-Jun and Sep-Oct: cost to serve never significantly above average, with no hour more than 7% above average
  - Jul-Aug and Nov-Mar: cost to serve significantly above average in afternoons (summer) and evenings (winter), with at least one hour 43% above average
- Based on this, suggest
  - **two month summer peak** (July – August)
  - **five month winter peak** (November – March)
- Previous experience suggests **four hour peak periods** achieve optimal load reduction and shifting
- Identified the four hour blocks with the highest average to cost serve

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DETERMINING PEAK TIME PERIODS – OPTION 2 CONSISTENT PEAKS

We compared the cost to serve load in each hour with the average cost to serve load

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

61% above average cost to serve during peak period

- Consistent peak time period across the year
- Selected peak period hours to capture as many individual high cost to serve hours as possible, while ensuring peak price signal was not excessively diluted

Red = highest cost to serve, **Green** = lowest cost to serve

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DETERMINING SUPER OFF-PEAK TIME PERIODS – OPTIONS 1 AND 2

Cost heatmap shows that overnight hours are consistently below average cost to serve

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

- Applied two criteria:
  1. Cost to serve must be below average
  2. Consistent super off-peak hours across the year

46% below average cost to serve for super off-peak hours

Red = highest cost to serve, **Green** = lowest cost to serve

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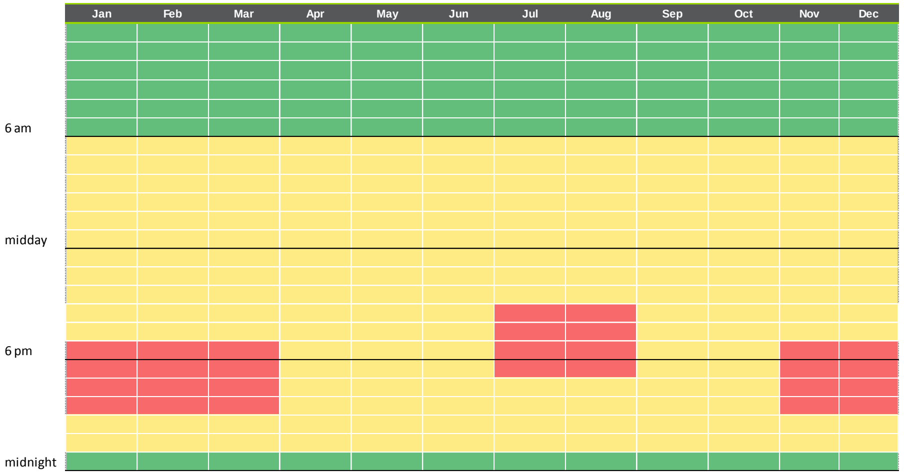
TOD TIME PERIODS

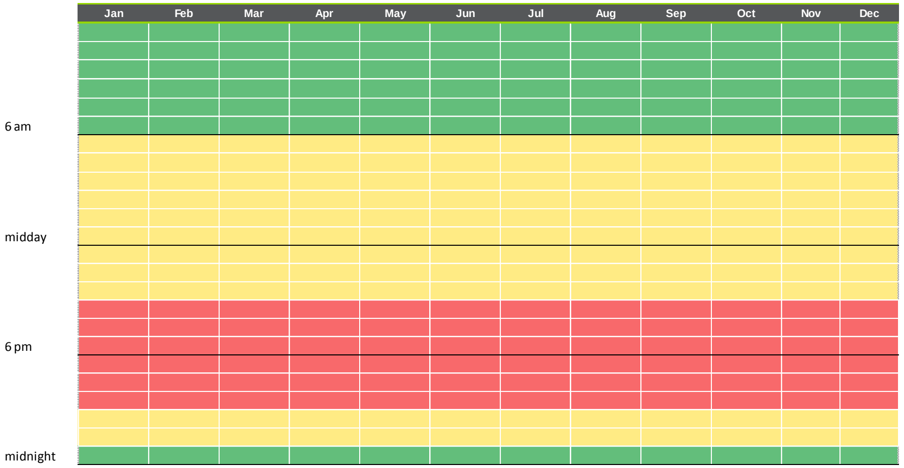
Option 1: Targeted peak periods

	Winter (Nov – Mar)	Summer (Jul – Aug)	Shoulder (Apr – Jun, Sept – Oct)
Super off-peak	11pm – 6am	11pm – 6am	11pm – 6am
Off-peak	6am – 5pm and 9pm – 11 pm	6am – 3pm and 7pm – 11 pm	6am – 11pm
Peak	5pm – 9pm	3pm – 7pm	n/a



Option 2: Consistent peak periods

	All year
Super off-peak	11pm – 6am
Off-peak	6am – 3pm and 9pm – 11 pm
Peak	3pm – 9pm



Super off-peak
Off-peak
Peak

* Shoulder season prices apply on all weekends and public holidays

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TOD RATES – ADDERS / DISCOUNTS TO EXISTING BLOCK TARIFFS

Option 1A: embedded costs allocated, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-2.4	29%
Off-peak	-0.1	64%
Peak	6.4	7%

Option 1B: no embedded cost allocation, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-0.8	29%
Off-peak	0.1	64%
Peak	0.7	7%

Option 1C: LMP allocation, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-1.9	29%
Off-peak	0.4	64%
Peak	1.8	7%

Option 2A: embedded costs allocated, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-2.4	29%
Off-peak	-0.1	53%
Peak	2.7	18%

Option 2B: no embedded cost allocation, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-0.8	29%
Off-peak	0.1	53%
Peak	0.4	18%

Option 2C: LMP allocation, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-1.9	29%
Off-peak	0.4	53%
Peak	1.2	18%

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TOD RATES – AS AVERAGE RATES

Option 1A: embedded costs allocated, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.2	29%
Off-peak	9.5	64%
Peak	16.0	7%

Option 1B: no embedded cost allocation, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	8.8	29%
Off-peak	9.7	64%
Peak	10.3	7%

Option 1C: LMP allocation, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.6	29%
Off-peak	10.0	64%
Peak	11.4	7%

Option 2A: embedded costs allocated, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.2	29%
Off-peak	9.5	53%
Peak	12.3	18%

Option 2B: no embedded cost allocation, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	8.8	29%
Off-peak	9.7	53%
Peak	10.0	18%

Option 2C: LMP allocation, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.6	29%
Off-peak	9.9	53%
Peak	10.8	18%

INDICATIVE MARGINAL COSTS

Indicative marginal costs

Function	Source	Cost (2020, $/kW-year)	Cost (2020, c/kWh)*
Transmission	Mendota Group analysis of 30 US utilities (2014)	$25	1.7
Distribution	Mendota Group analysis of 30 US utilities (2014)	$52	3.5
Generation Capacity	Gross CT Cost of New Entry (LRZ 1)	$95	6.5
Energy	Residential load weighted LMP, 6-10 pm (2020)		4.3
Total Rate during Peak Hours			**16.0**

Sample marginal costs ($/kW-yr)

	Transmission	Distribution
Otter Tail Power (2016)	$72	$31
Xcel Energy (2014)	$14	$39
Mendota Group analysis average value (2014)	$22	$46

* Fixed costs spread across a four hour peak period

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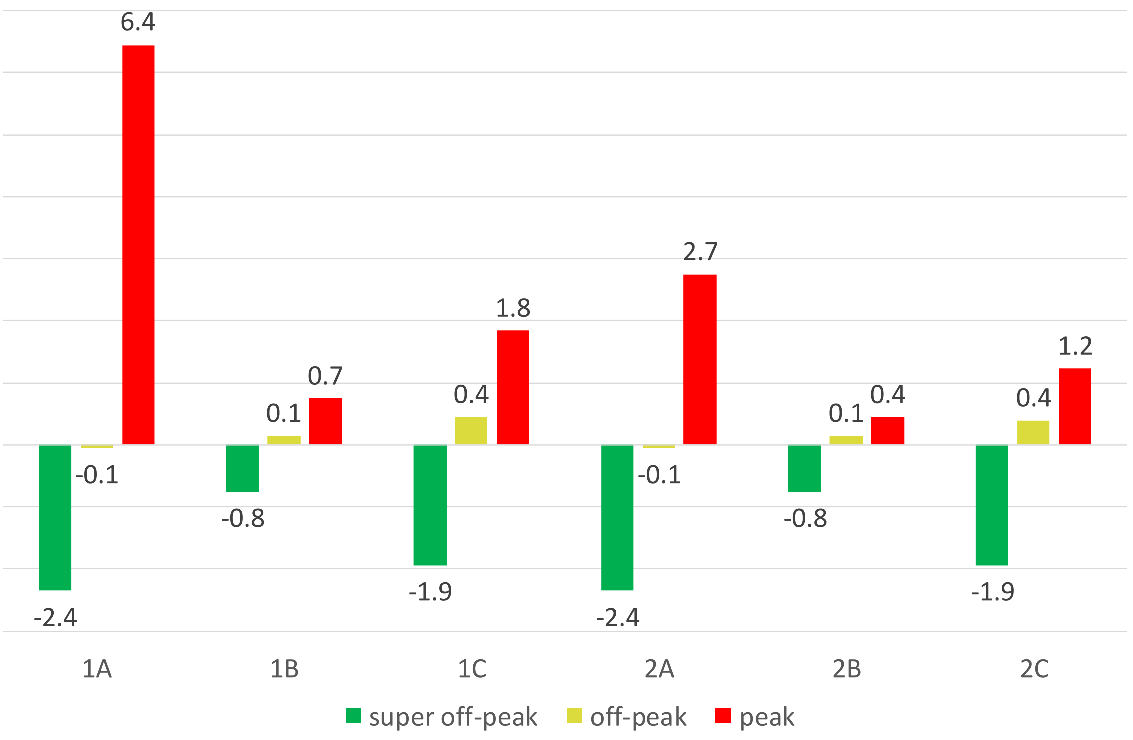
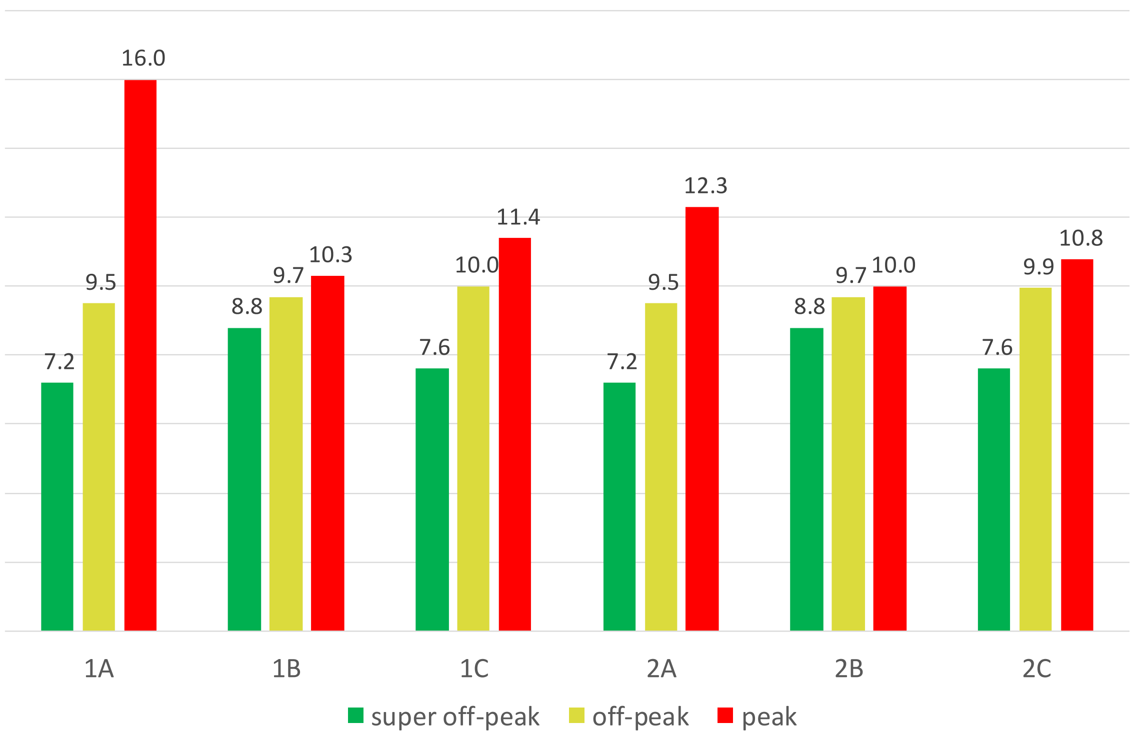
TOD RATES – CHARTS

TOD rates – as adders / discounts



TOD rates – as average rates



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TOD RATE OPTIONS – BILL IMPACT

	kWh	1A $ p.a.	%	1B $ p.a.	%	1C $ p.a.	%	2A $ p.a.	%	2B $ p.a.	%	2C $ p.a.	%
RC_1	3,496	-2	-1%	-1	0%	0	0%	-2	-1%	0	0%	0	0%
RC_2	6,087	1	0%	0	0%	2	0%	-1	0%	0	0%	2	0%
RC_3	8,335	2	0%	0	0%	2	0%	1	0%	0	0%	3	0%
RC_4	12,604	9	1%	2	0%	10	1%	11	1%	3	0%	11	1%
RC_5	16,307	7	0%	0	0%	8	0%	4	0%	2	0%	8	0%
RC_6	27,054	-19	-1%	-8	0%	-10	0%	-30	-1%	-7	0%	-11	0%
RN_1	4,018	3	1%	0	0%	2	0%	1	0%	0	0%	2	0%
RN_2	6,984	5	1%	1	0%	5	1%	5	1%	1	0%	6	1%
RN_3	8,020	3	0%	-1	0%	1	0%	0	0%	0	0%	1	0%
RN_4	14,994	1	0%	-2	0%	1	0%	-4	0%	-1	0%	1	0%
RN_5	16,545	34	2%	6	0%	22	1%	30	2%	7	0%	23	1%
RN_6	28,127	-18	-1%	-9	0%	-13	0%	-31	-1%	-8	0%	-14	0%
RW_1	4,198	-2	0%	-1	0%	0	0%	-1	0%	0	0%	0	0%
RW_2	7,692	-5	-1%	-2	0%	-3	0%	-6	-1%	-2	0%	-3	0%
RW_3	12,099	17	1%	3	0%	13	1%	16	1%	4	0%	14	1%
RW_4	18,000	7	0%	-2	0%	2	0%	-3	0%	-1	0%	1	0%
RW_5	27,931	33	1%	6	0%	26	1%	26	1%	8	0%	27	1%
RW_6	95,093	-5	0%	-5	0%	26	0%	7	0%	4	0%	34	0%

Initial bill impacts are muted

- Adder / discount structure of TOD rates means that overall usage level doesn’t drive bill impacts
- Calculated bill impacts customer profiles in MP’s Load Research study (as used in most recent rate design)
- For these profiles, no bill impact exceeds 2%
- Further bill impact analysis using individual customer data will be carried out in the future

 /

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THANK YOU

LON HUBER

928.380.5540

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Minnesota Power Advanced Time of Day Rate
Meeting 3: December 10th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

10:00am – 2:00pm

Meeting Notes

1. **What are the strengths of what was presented?**
   - General design and approach– 3 periods seems right, pricing seems justified based on underlying costs
   - On the right track – targeted, shorter peak. People will be better able to respond
   - Simpler than existing pilot
   - Seems like it will benefit most people
   - 6 different options provides flexibility to figure out the best solution
2. **What improvements would stakeholders suggest (not necessarily to be figured out by 2/1/19)?**
   - Look at keeping the 4-hour peak, but bridge the summer and winter so there are two seasons instead of three
   - Look at option of a 5-hour peak, but year-round
   - Look at making the super off-peak an hour shorter (interest in maximizing super off-peak shift)
   - Show how a higher peak:off-peak ratio would affect bills
   - More on treatment (or exclusion) of different customer groups if doing opt-out – net metering, electric heat, etc.
     - How this would work for net metering customers (depends on monetary vs. kWh crediting)
   - Discuss whether IBR would discontinue, and if so, how
   - Marketing and education – some discussion of a rough plan (but acknowledging that it doesn't need to be finalized before rate is approved)
   - Ensure a large enough differential between on and off-peak periods to encourage behavior change
   - Better understand the significance of allocation decisions in the model (e.g., MISO for generation capacity vs. MP)

- Deeper dive into different user profiles – in each scenario, how would different cases impact particular users?

3. **How well do the draft recommendations align to the design principles? (and/or are there suggested changes to the design principles?)**
   - Costs and benefits – acknowledge benefits might be difficult to measure. Don't want to see a proposal where costs outweigh benefits (incremental program costs/benefits). Not including metering, but education, marketing, admin.
   - Low-income – can look more into it. Question of whether bill impacts warrant indemnification. Need to discuss IBR as part of this.
     - Would like to see a transitional plan, at least. Could provide a buffer.
     - Issue of missing people who aren't on LIHEAP assistance.
     - Question about renters with multiple tenants on a single meter – how will they be addressed?
   - EE/RE/GHG – looking good from the standpoint of three TOU periods. Just need to optimize this.
   - Rates that accurately reflect costs of energy – good
   - Opt-out – some difference of opinion
     - One perspective -- Weigh costs vs. benefits. Opt-out is default, but open to MP determining if it's not appropriate.
     - Another perspective -- Would like to see everybody on this rate
   - Access and tools – must-have down the road
     - Would like stronger customer interface with data – can customer actually interact with their usage data?
     - Co-market efficiency programs and technologies that can help with responding to TOU periods
   - "TOD plus" products (CPP, PTR) – stakeholders still open to considering as an opt-in, but not necessary (would require either a CPP with a separate TOD design, or a PTR on top)
4. **Does a TOD rate seem worth it for MN Power? Why or why not?**
   - Yes – a step forward in creating a modern rate design. Open question about the benefit we're hoping to get.
     - Question about timing – might be 5-10 years before market prices are high enough to make this product worthwhile
     - Multiple benefits – peak shaving, integration of RE during off-peak.
   - No – maybe not enough benefits to justify.
5. **What additional information would you like to see (or not see)?**
   - Peak ratios in B and C didn't seem high enough to warrant further detail
   - Option A3 – in between A1 and A2
   - Rough plan for marketing and customer engagement
6. **What, if anything, would cause you to oppose a TOD rate?**
   - If costs are high and benefits are small
   - If differential between periods is not high enough to solicit a worthwhile behavioral response

- If some advocates are strongly against, may make it difficult for similar advocates to disagree
- Question about inclusion of IBR – some would like to keep it, some would like to see it go away
  - Against IBR – complexity increases with TOD; disincentivizes beneficial electrification; may be better ways to incentivize conservation; with more RE on the system, want TOD over IBR to incentivize usage during certain periods.
  - Some discussion about impacts on low users (especially low-income low users)
  - IBR is arguably less fair than TOD
- Marketing and outreach – want to see a defined plan to start with.
  - What about for opt-out? Means education about the change, and how to respond including suggestions to maximize savings. Maybe an option to revert if not comfortable.
- Opt-in approach – make the effort of designing the rate worthwhile. Impact on benefits vs. costs.
- No plan for net metering customers. Open to discussing a plan, but would like to see something.
  - How many net metering customers does MP have?

7. Reflection, Wrap-up, and Next Steps

- Need to prioritize analytics, and what the next steps are
- Medically necessary customers should be excluded from being automatically opted in
- What are the most important things to address in the February 1st filing?
  - Specific proposal on the timing and pricing, including seasonality (if including)
  - Raise as many issues now before there is a tariff up for discussion – get the Commission's input upfront
  - Balance what can be done in a quality fashion before Feb. 1st.
  - Acknowledge that net metering will need to be addressed
- What will be in the filing?
  - Learnings from this process
  - Can't file a tariff yet
- Another meeting?
  - Would be most helpful to see a concrete idea to offer constructive feedback
  - Happy to review before filing, but not necessary
  - Preferable to have a webinar meeting
  - Goal – come back with 1-2 options that are fully baked

Minnesota Power Advanced Time of Day Rate
Meeting 4 (Webinar): January 11th, 2019

10:00am – 11:30am

Please join us by using this Zoom link

Meeting Objectives:

1. Solicit feedback on the final rate design options moving forward
2. Address any outstanding questions
3. Understand next steps for Minnesota Power's proposed Time of Day rates

Draft Agenda

10:00 – 10:15 am	Welcome, Intro's, Recap from Meeting 3
10:15 – 11:15 am	Presentation and Q&A: Revised Rate Designs • What did stakeholders like? • Any major concerns?
11:15 – 11:30 am	Next Steps • Address outstanding issues and questions
11:30am	ADJOURN

MINNESOTA POWER TOU RATE DESIGN
JANUARY STAKEHOLDER WEBINAR

LON HUBER

JANUARY 2019

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INTRODUCTION

1. Updated rate options
2. Bill impact analysis and update
3. Exclusions
4. General Feedback

COST ALLOCATION OPTIONS

Option A: allocation of embedded costs using load duration method

- Allocates embedded costs across time periods based on the load that caused these costs
- (further detail on next slides)

Option B: no allocation of embedded costs

Not progressed further

- Treats embedded costs as sunk costs
- Generation and network capacity have already been built
- Future consumption decisions cannot reduce these embedded costs, so costs recovered evenly across all time periods
- (provides a short-run view of marginal cost of service: only LMPs are marginal, all other costs are sunk)

Option C: LMP allocation approach

Not progressed further

- Allocates embedded costs across time periods based on LMPs, as these are readily available and reasonable proxy for load

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COST ALLOCATION OPTIONS – DETAIL

MP's annual residential cost to serve is broken down by component and allocated across 8,760 hours

2018 costs		Option A: Embedded cost allocation Allocated to each hour using:		Rationale	Option B: No embedded cost allocation. Allocated to each hour using:	Rationale	Option C: LMP allocation approach Allocated to each hour using:	Rationale
Capacity	$47m	Generation capacity	MISO load	MP's generation capacity requirements (imposed by MISO) are driven by its load during summer afternoons when MISO load peaks	Allocated evenly	Costs are sunk, only marginal costs are allocated Not progressed further	MISO LMP (energy price) at MP node	LMPs include generation and transmission cost signals, and are a reasonable proxy for distribution cost signals also Not progressed further
		Transmission capacity	Minnesota Power gross load	Gross load drives the capacity requirements (and thus cost) of MP's transmission system				
		Distribution capacity	Minnesota Power residential load	Residential peak demand is the key driver of the capacity (and thus cost) of the distribution system in residential areas				
Energy	$31m	MISO LMP (energy price) at MP node		The LMP represents the cost to Minnesota Power of supplying energy to its ratepayers, either through self-generation or purchases through MISO	(as Option A)		(as Option A)	
Customer	$27m	Allocated evenly		These costs (e.g. metering, customer services) do not vary with load so are recovered in part through the monthly Service Charge with remainder shared evenly across all hours	(as Option A)		(as Option A)	

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PEAK PERIOD OPTIONS

Option 1: Four hour targeted peak periods, with shoulder

- Four hour peak periods that vary by season
- Shoulder months with no peak periods
  - 5pm – 9pm from Nov to Mar (five months)
  - 3pm – 7pm from Jul to Aug (two months)
  - No peaks from Apr to Jun and Sep to Oct (five months)

Option 2: Six hour consistent peak periods

- Six hour peak period across the year
  - 3pm – 9pm

(NEW) Option 3: Four hour targeted peak periods, no shoulder

- Four hour peak periods that vary by season
- No shoulder months
  - 5pm – 9pm from Sep to May (nine months)
  - 3pm – 7pm from Jun to Aug (three months)

(NEW) Option 4: Five hour consistent peak periods

- Five hour peak period across the year
  - 4pm – 9pm

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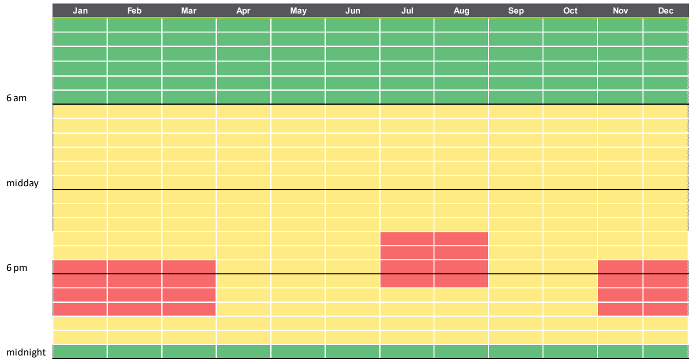
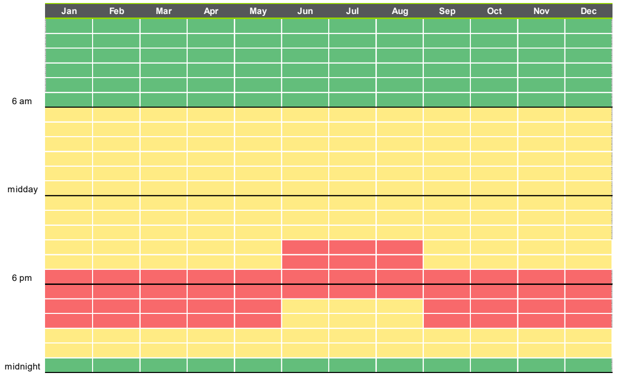
PEAK PERIOD OPTIONS

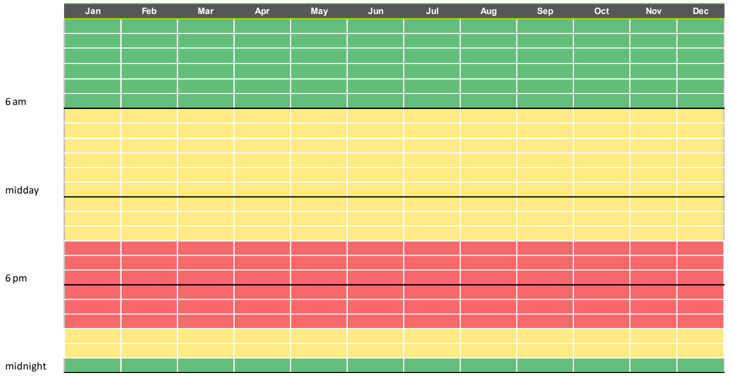
Option 1: Four hour targeted peak periods, with shoulder



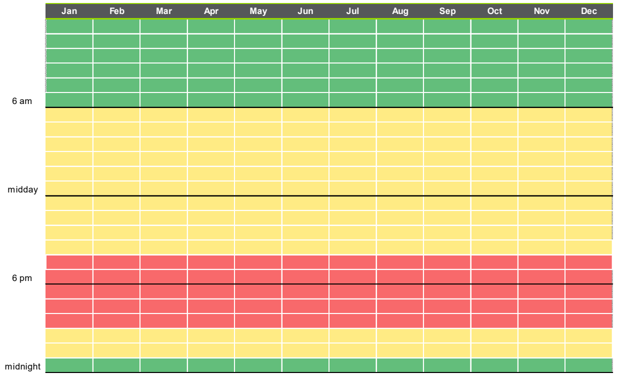
(NEW) Option 3: Four hour targeted peak periods, no shoulder



Option 2: Six hour consistent peak periods



(NEW) Option 4: Five hour consistent peak periods



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SUPER OFF-PEAK PERIOD OPTIONS

Original option: seven hour super off-peak

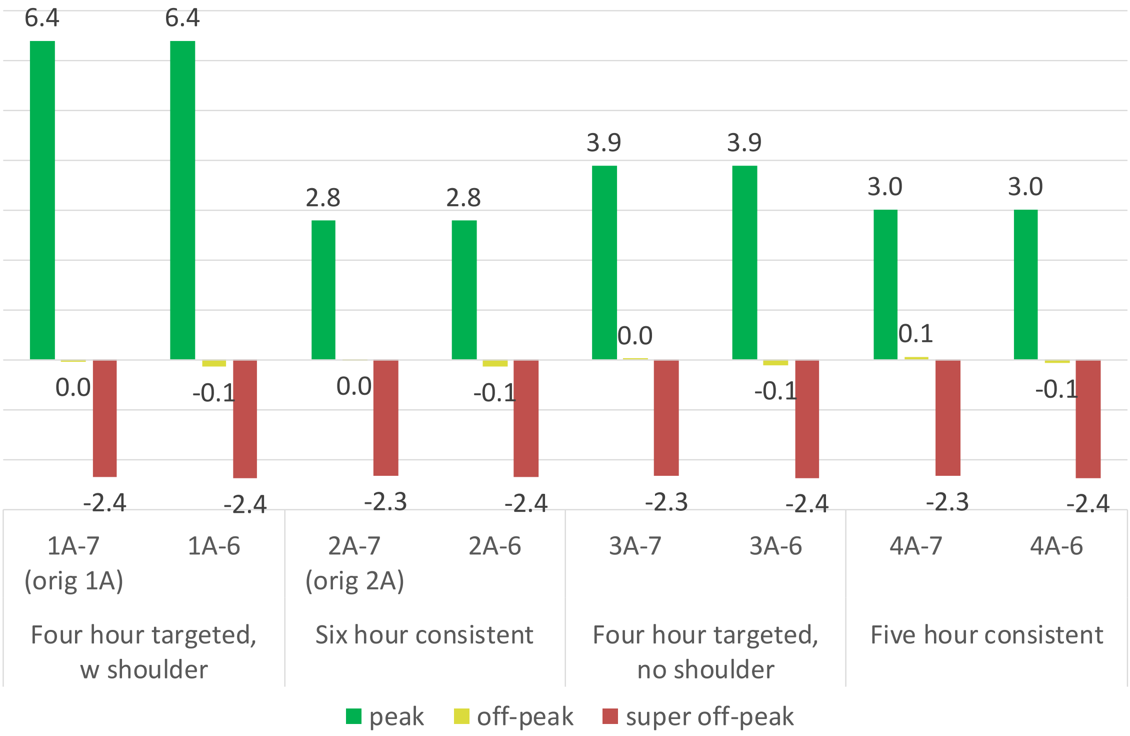
- 11pm – 6am

(NEW) Alternate option: six hour super off-peak

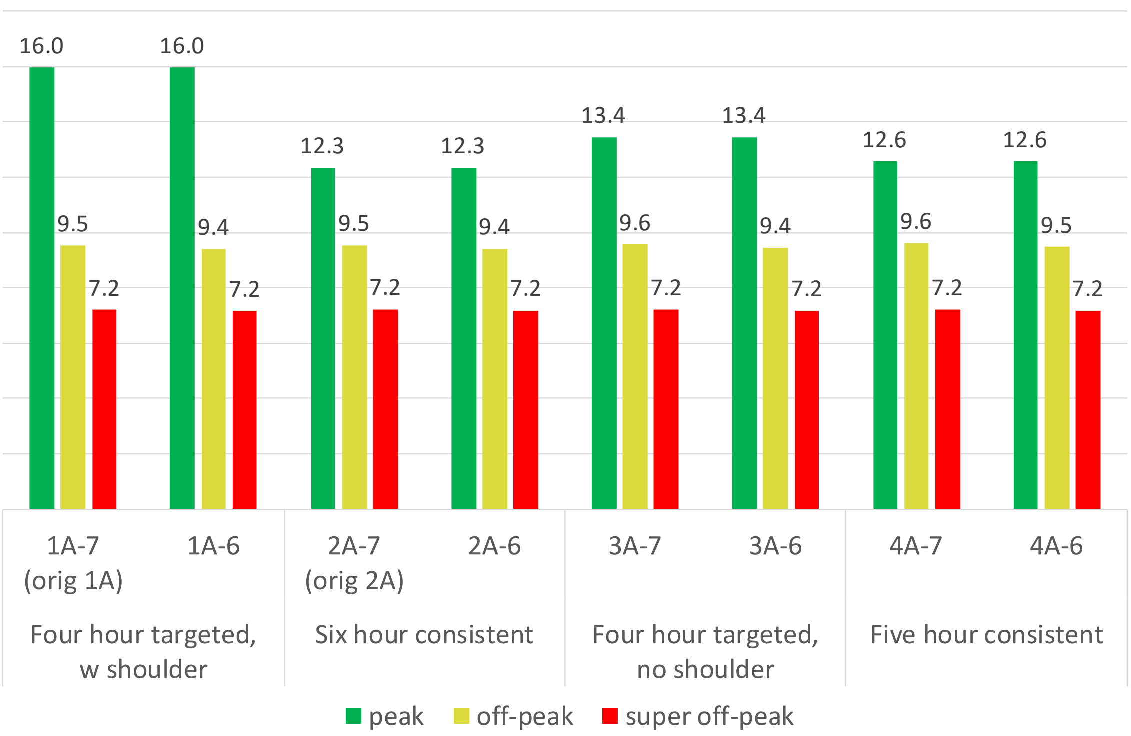
- 11pm – 5am

TOD RATES – CHARTS

TOD rates – as adders / discounts



TOD rates – as average rates



-7 = seven hour super off-peak (original option)
-6 = six hour super off-peak (new option)

TOD RATE OPTIONS – IMPACT OF DIFFERENT COST STRUCTURE

Cost structure (2018 costs)

	Actual costs	Alternate costs
Capacity	$47m	$50m
Energy	$31m	$35m
Customer	$27m	$20m

TOD rates – option 4A-7 (five hour peak, 4pm – 9pm, year round)

	Actual costs	Alternate costs
Peak	12.6c	12.8c
Off-peak	9.6c	9.6c
Super off-peak	7.2c	7.0c

TOD RATE OPTIONS – HOW WOULD A HIGHER PEAK RATIO AFFECT BILLS?

	kWh	1A-7 $ p.a.	%	2A-7 $ p.a.	%	1-high diff $ p.a.	%
RC_1	3,496	-2	-1%	-2	-1%	**-3**	**-1%**
RC_2	6,087	1	0%	-1	0%	**3**	**1%**
RC_3	8,335	2	0%	1	0%	**5**	**1%**
RC_4	12,604	9	1%	11	1%	**19**	**2%**
RC_5	16,307	7	0%	4	0%	**15**	**1%**
RC_6	27,054	-19	-1%	-30	-1%	**-33**	**-1%**
RN_1	4,018	3	1%	1	0%	**6**	**2%**
RN_2	6,984	5	1%	5	1%	**11**	**2%**
RN_3	8,020	3	0%	0	0%	**6**	**1%**
RN_4	14,994	1	0%	-4	0%	**4**	**0%**
RN_5	16,545	34	2%	30	2%	**67**	**4%**
RN_6	28,127	-18	-1%	-31	-1%	**-31**	**-1%**
RW_1	4,198	-2	0%	-1	0%	**-3**	**-1%**
RW_2	7,692	-5	-1%	-6	-1%	**-8**	**-1%**
RW_3	12,099	17	1%	16	1%	**33**	**3%**
RW_4	18,000	7	0%	-3	0%	**15**	**1%**
RW_5	27,931	33	1%	26	1%	**67**	**2%**
RW_6	95,093	-5	0%	7	0%	**-1**	**0%**

New option 1-high diff

	1-high diff	1A-7
Peak	22.3c	16.0c
Off-peak	9.4c	9.5c
Super off-peak	5.1c	7.2c

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EXCLUSIONS?

1. Medically dependent customers
2. ?

NET METERING

- Significant metering and billing challenges

FEEDBACK?

- Any questions, concerns, comments?

Minnesota Power Advanced Time of Day Rate
Meeting 4 (Webinar): January 11th, 2019

10:00am – 11:30am

Meeting Description: This is the fourth and final meeting of this series. In the first two meetings, the group learned about Minnesota Power's metering infrastructure and load profile and worked to develop a set of design principles for the TOD rate. In the third meeting, Minnesota Power presented a set of draft TOD rate options, which the group evaluated against the design principles. The group has asked Minnesota Power to come back in this final webinar meeting with 1-2 fully developed rate design options for final feedback.

Meeting Objectives:

1. Solicit feedback on the final rate design options moving forward
2. Address any outstanding questions
3. Understand next steps for Minnesota Power's proposed Time of Day rates

Meeting Notes

1. **Clarifying Questions:**
    a. Why does shifting from 7 hr to 6 hr super off peak not change the off-peak rate?
        i. Hours have similar costs, so when you take an hour out, it doesn't change the average cost.
    b. Slide 9 -- Surprised at how little shifted between the two cost structures, in terms of the rates.
        i. Oliver and Lon will follow-up by email. Could be that it's the option to bridge on-peak across the entire year, so impacts are muted.
    c. Slide 10 – can you unpack this?
        i. These are different load profiles, but they're averaged into these annual usage buckets and geographic zones
        ii. This shows the impact if a customer does NOT change behavior at all. Impacts for customers that shift load will be higher.
    d. Exclusions – haven't made any final decisions
    e. For net metering – can't you net meter by production within each TOU period?
        i. Request is to net meter within the TOD periods; question is whether the metering technology and billing software can allow for that.
        ii. MP will check into this and follow up with the group.

2. **Discussion Questions:**
    a. Exclusions/inclusions?
        i. Net metering -- estimate about 200 customers. Need to determine how to bucket them to make sure net metering is fair.
        ii. If company is proposing advanced metering, and cost recovery on that, then it seems like it should be expected that these billing issues will be worked out.
    b. What do stakeholders like?
    c. Where are there remaining areas for improvement?
        i. MN Power EV rate has a longer off-peak period and has a lower price per kWh (4 cents). Given how low LMP's are in Minnesota over night, 7 cents seems too high.
            1. This is up to date, but slightly historic in terms of renewable energy build out.
            2. MP load is pretty flat compared to other systems.
            3. Could there be a more forward-looking analysis that assumes more renewables, so that this rate is accurate in the future?
        ii. Differential and options
            1. One perspective -- Price ratios for consistent peak periods aren't sharp enough – leads to options 1A and 3A. 3A is easier to market and educate, but less of a differential.
            2. Another perspective -- Like the five hour consistent option for getting customer engagement.
            3. A third perspective – see advantages of 5 hour consistent, but like a slightly higher peak rate.
            4. Forward-looking design would help to spread out the differential.
            5. Lon -- Option 3 is still within the realm of reason to have customers respond, based on experience from other utilities.
            6. Difficult to increase the differential based on the load profile. Very little system peaking needs.
        iii. Benefits of a TOD rate
            1. What are the huge benefits of this going into the future?
            2. What's the impact on load for 1A and 3A? Is one more impactful than the other?
                a. Pretty hard to tell, but see an incremental response rate from a 12 cents peak to a 14 or 16 cents rate.
            3. How does this change with a more forward-looking analysis?
                a. More focused peak, lower off peak rate
        iv. Education
            1. Current rate is pretty complicated, so not as many concerns about that piece of it.
        v. EV rate – off peak is lower because on-peak period is so much longer.
        vi. Option not on the screen – blend of option 4 and 1 – has "no-peak" seasons in Spring and Fall, but peak period is consistent when it does occur in Summer and Winter
    d. Conclusions

i. Desire for a forward-looking analysis that takes into account more renewables on the system
ii. New option 5 concept – less complexity, which is good, but decision has to be around system peak, schedule, and prices – needs to be a package
iii. Still concerns about whether this is worthwhile.
iv. Is one of these options better than the status quo? Perspectives of the group include the following:
    1. Option 3, 4 and 5 are all workable and probably better than status quo
    2. Without seeing impacts to peak, conflicted about whether a TOD rate is worth the effort
    3. Could live with 3, 4, or 5. Not sure if it’s worth it.
    4. Can add value through TOD+ options
v. Concern about customers changing their behavior