Jenna Warmuth
Senior Public Policy Advisor
218-355-3448
jwarmuth@mnpower.com

February 20, 2019

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's May 1, 2018 Compliance Filing for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project
Docket No. E015/M-12-233

Dear Mr. Wolf:

Minnesota Power submitted its 6-month compliance filing in the docket on November 1, 2017. Along with reporting all required information, the Company also requested an extension of its 12 month compliance date.

In its February 13, 2018 Order in the docket, the Commission accepted Minnesota Power's 6-month compliance report as complete. In response to the Company's request for an extension on the 12-month compliance date, the Commission bifurcated the original compliance deadlines. The Commission ultimately required Minnesota Power to file a 12-month compliance report on May 1, 2018, but divided the contents of the original 12-month compliance report into two reports, one due on May 1, 2018, and another September 1, 2018. Order Points 2 and 3 from the February 2018 Order in the docket read as follows:

- By May 1, 2018, Minnesota Power shall file a 12-month compliance report that discusses feedback from customers and lessons learned from the TOD Rate Pilot.
- By September 1, 2018, Minnesota Power shall file a compliance report that presents alternative rate designs and TOD periods for its TOD rate.

In its August 20, 2018 Order in the docket, the Commission accepted Minnesota Power's May 1, 2018 compliance report as complete and took no action on the Company's proposed options for altering the TOD Rate. The Commission also ordered the discontinuation of formal evaluation of the current TOD Rate and its participants, and beginning one year from the date of the

Commission's Order, and for a period of two years, required Minnesota Power to submit annual informational filings providing a summary of the TOD Pilot Program, including participation rates, an update on meter communications infrastructure, and plans to offer a system-wide rollout of residential TOD rates. The Order also extended the deadline for Minnesota Power to file its 12-month compliance report on alternative rate designs from September 1, 2018, to February 1, 2019. The Order also requires the Company to provide the following information in this compliance report:

- system information about its peak demand, its peak demand consistent with Midcontinent Independent System Operator ("MISO"), and the hourly cost of meeting its peak demand;
- more information about Minnesota Power's Meter Data Management request for proposals; and
- a discussion of what goals Minnesota Power believes should be addressed by the TOD rate.

This compliance filing satisfies the Company's 12-month compliance reporting requirement, outlines the Company's stakeholder engagement efforts and outcomes, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory. The Company looks forward to the opportunity to work with the Commission to review the information and recommendations contained in its Time-of-Day Rate February 20, 2019 Compliance filing.

Please contact me at the number or email above with any questions related to this Compliance filing.

Respectfully,

Jenna Warmuth

JW:sr
Attach.

MINNESOTA POWER'S TIME-OF-DAY RATE COMPLIANCE

In the Matter of Minnesota Power's Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project

DOCKET NO. E015/M-12-233

February 20, 2019

Jenna Warmuth (MP)

Executive Summary

Minnesota Power outlines through this compliance filing the Company's stakeholder engagement efforts and outcomes, meter data management considerations, alternative rate design analysis, customer bill impacts and rate implementation considerations, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory.

Purpose of a Time-of-Day Rate

Time-of-Day rates are an evolution in rate design aimed at creating customer behavior changes in energy use. A Time-of-Day rate structure uses price signals to encourage reduction of energy demand when system costs are high, and subsequent shifting of energy demand to times when system costs are low. By facilitating customer behavior change in energy usage, a Time-of-Day rate structure could be seen as a precursor to flexible energy use rates in the future that support continued integration of variable renewable energy supply into the system and overall decarburization of energy usage.

Stakeholder Process

The Company completed a robust and informative stakeholder process enhanced by the facilitation skills of the Great Plains Institute and Center for Energy and the Environment. The Stakeholder process included a series of four stakeholder meetings. This process established two objectives and six "must have" principles as a baseline for the alternative rate design analysis, along with other considerations imperative to be considered in development of innovative rate offerings. The Company also facilitated two in-person customer meetings in its service territory along with an online customer survey.

MDM and Metering Considerations

The Company is currently deploying innovative rate and program enabling advanced metering infrastructure ("AMI") across its service territory. Over 50 percent of Minnesota Power's meters in the field are AMI, with current deployment at roughly 6-8% per year. Along with AMI deployment, Minnesota Power has previously addressed the need for a meter data management ("MDM") solution in relation to a system-wide rollout of a TOD rate. As communicated in this filing, Minnesota Power's planned MDM implementation and integration is a strategic investment for the Company beyond enabling TOD rates. In relation to TOD rates, the presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

Alternative Rate Design Analysis

The Company retained the expertise of Lon Huber of Navigant Consulting to augment its rate design and analysis. In this compliance filing Minnesota Power addresses, among other things, Minnesota Power and MISO's peak demand, the hourly cost of serving peak demand, and three options for alternative rate designs and peak periods.

Preferred TOD Rate Design Options - Average Prices (c/kWh):

	Option 1	Option 2	Option 3
Peak	16.8	13.8	14.9
Off-peak	9.2	9.2	9.2
Super off-peak	6.7	6.7	6.7

Final Rate Design Options – Time Periods:

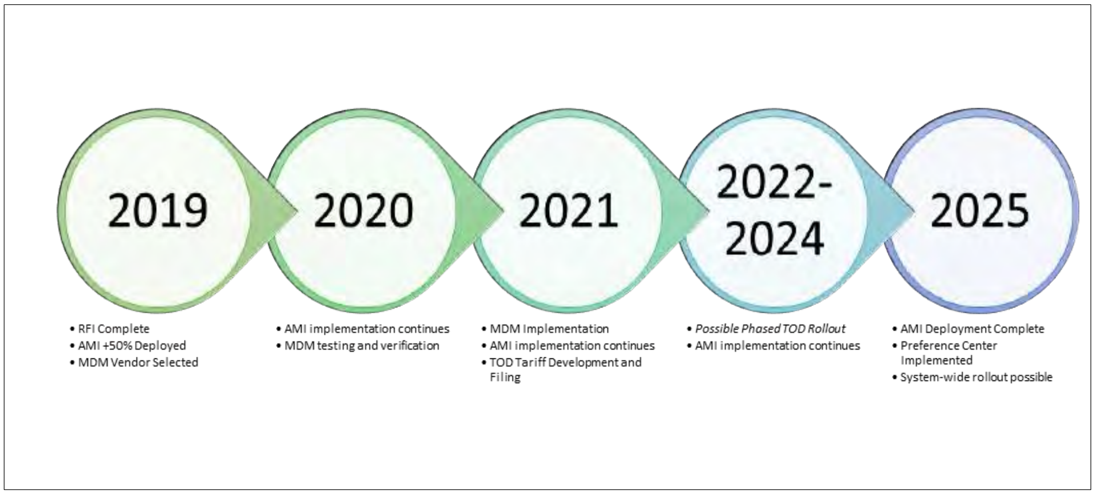
	Option 1	Option 2	Option 3
Peak:	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep	3:00 PM – 8:00 PM weekdays	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	All other times	All other times	All other times
Super off-peak	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM

Customer Bill Impacts

Stakeholders communicated clearly that bill impacts are a serious concern for some customer classes when considering implementation of a TOD rate. In this filing the Company has provided preliminary bill impact assessments and examples to give stakeholders and the Commission a cursory representation of how these preferred rate options would affect customers' bills. In general, the Company's initial analysis of the preliminary rate options does not demonstrate disparity of billing impacts between low income and standard residential customers.

Rate Implementation

With the complete deployment of AMI, Minnesota Power's AMI system will be technically capable of supporting a system-wide time varying rate offering. However, in all practicality, an MDM solution needs to be in place systemically before a system-wide rollout of this type of rate/program. Though there was not general consensus on a specific deployment plan, the stakeholder workgroup discussed the possibility of a phased deployment and produced a preliminary timeline for consideration as depicted below.



The Company also discusses key components of customer education, costs of full-scale implementation and future tracking, reporting, and measuring considerations required for a largescale TOD rate rollout.

Conclusion

The Company is pleased to share its findings from its important and informative TOD stakeholder process. Looking towards the future and examining innovative rate offerings ensures that the Company continues to meet its customer’s and stakeholder’s needs while also potentially providing benefits to the electric system.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project	Docket No. E015/M-12-233 **February 2019 Compliance Filing**

I. Introduction

Minnesota Power (or, "the Company") submitted its Petition for Approval of a Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project ("Petition") to the Minnesota Public Utilities Commission ("Commission") on March 20, 2012. This Petition sought Commission approval of its proposed rider for a residential Time-of-Day Rate ("TOD Rate" or "Rate") with Critical Peak Pricing ("CPP") for participants in Minnesota Power's Smart Grid Advanced Metering Infrastructure Pilot Project ("Pilot Project"). The Petition was approved on November 30, 2012 and the final rate was made available for customer adoption in October of 2014.

Minnesota Power submitted its first annual Compliance Filing ("Compliance Filing") for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project to the Commission on March 25, 2016. The Commission approved Minnesota Power's petition to continue the Time-of-Day Rate for existing participants in its February 15, 2017 Order in the docket. In this Order the Commission approved modifications to Minnesota Power's Pilot Rider for Residential Time-of-Day Service as outlined below:

- Adjust rate design to assume 25 hours of CPP (instead of 100); and
- Adjust the on-peak adder to \$0.04870/kWh (instead of \$0.01415/kWh).

These modifications were effective May 1, 2017. In addition, the Commission required Minnesota Power to file compliance reports 6 and 12 months from the date the new rate became effective. Minnesota Power submitted its 6-month compliance filing on November, 1, 2017. Along with reporting all required information outlined in the Notice, the Company also requested an extension of the 12 month compliance date.

In its February 13, 2018 Order, the Commission accepted Minnesota Power's 6-month compliance report as complete. In response to the Company's request for an extension on the 12-month compliance date, the Commission bifurcated the original compliance deadlines. The

Commission ultimately required Minnesota Power to file a 12-month compliance report on May 1, 2018, but divided the contents of the original 12-month compliance report into two reports, one due on May 1, 2018, and another September 1, 2018.

Minnesota Power filed its 12-month compliance report on May 1, 2018. The May 1 Report outlined experiences and lessons learned from the prior 12 months of the Time-of-Day Rate Pilot. In the Report, the Company proposed three options for current participants of the Time-of-Day Rate for the Commission's consideration.

- Option A - Discontinue the TOD Rate Pilot.
- Option B - Remove the CPP component and assume those hours as on-peak, adjusting the on-peak adder from $0.04870/kWh to $0.05875/kWh (approximately 1 cent per kWh) while retaining the off-peak discount at $-0.02990.
- Option C - Remove the CPP component. Retain the on-peak adder at $0.04870/kWh. Adjust the off-peak discount from -$0.02990/kWh to -$0. 02480/kWh.

In its August 20, 2018 Order in the docket, the Commission accepted Minnesota Power's May 1, 2018 compliance report as complete and took no action on the Company's proposed options for altering the TOD Rate. The Commission also ordered the discontinuation of formal evaluation of the current TOD Rate and its participants, and beginning one year from the date of the Commission's Order, and for a period of two years, required Minnesota Power to submit annual informational filings providing a summary of the TOD Pilot Program, including participation rates, an update on meter communications infrastructure, and plans to offer a system-wide rollout of residential TOD rates. The Order also extended the deadline for Minnesota Power to file its 12-month compliance report on alternative rate designs from September 1, 2018, to February 1, 2019. The Order also requires the Company to provide the following information in this compliance report:

- system information about its peak demand, its peak demand consistent with Midcontinent Independent System Operator ("MISO"), and the hourly cost of meeting its peak demand;
- more information about Minnesota Power's Meter Data Management request for proposals; and
- a discussion of what goals Minnesota Power believes should be addressed by the TOD rate.

This compliance filing satisfies the Company's 12-month compliance reporting requirement, outlines the Company's stakeholder engagement efforts and outcomes, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory. It is important to note that no conclusive stakeholder consensus was reached in terms of a preferred rate design. As communicated through this filing, the stakeholder workgroup reviewed multiple versions of differing rate designs and ultimately did not reach consensus regarding which rate was most reasonable, or if a time varying rate ultimately makes sense for Minnesota Power's system considerations. This filing outlines the progress made thus far via the stakeholder workgroup. There are certain components of the alternative designs (i.e., customer exclusions, and programming costs) that would need to be clarified further in a future program and tariff filing. These design components will require additional thoughtful and proactive stakeholder input prior to a program filing and are discussed in the appropriate sections within this filing.

Minnesota Power does not view the rate alternatives presented in this filing as final, and asserts that the Company should not implement a full scale Time-of-Day offering until a Meter Data Management ("MDM") solution is fully implemented and functional for its service territory. This filing is intended to represent a step forward in developing appropriate time varying rates that are built from stakeholder input, Minnesota Power's specific system considerations, and customer preferences.

II. Stakeholder Process

In its February 2018 Order in the docket, the Minnesota Public Utilities Commission ordered Minnesota Power to engage stakeholders in evaluating alternative rate designs and TOD periods for a system-wide TOD rate. In response to the Commission's Order, Minnesota Power held a series of four meetings with stakeholders, and two in-person customer meetings in order to gain stakeholder input into the Company's prospective TOD Rate designs. These meetings have proven to be a thoughtful and constructive exercise for both the Company and its stakeholders, as the meetings highlighted the unique aspects of Minnesota Power's system considerations for stakeholders and facilitated a positive dialogue and shared learning between participants.

Minnesota Power retained the expertise of Lon Huber (Navigant Consulting) to augment the Company's research and analysis during this stakeholder process. Mr. Huber and his team were instrumental in using their professional expertise to incorporate stakeholder input on the complex and provocative topics inherent in TOD rate design. Mr. Huber is a nationally recognized expert on time varying rate design and is well known to, and respected by, the Commission and Minnesota Power's stakeholders.

Minnesota Power also procured external facilitation resources by partnering with the Great Plains Institute and the Center for Energy and the Environment. Minnesota Power kicked off its stakeholder process to evaluate alternative rate designs in September of 2018. A full summary of the meetings and stakeholders perspectives is provided as Attachment A to this filing.

1. MEETING SUMMARIES

Minnesota Power held its first stakeholder meeting at the Great Lakes Aquarium in Duluth, MN on Tuesday, September 11, 2018. This meeting focused on current metering and communications infrastructure and shared objectives and design principles. The second meeting took place at the Mill City Museum in Minneapolis on Friday, September 28, 2018. This meeting focused on Minnesota Power's system load characteristics and findings from its Smart Grid Pilot. The third meeting was once again held at the Mill City Museum on December 10, 2018. The meeting focused on feedback from Minnesota Power's customer survey and workshops and Minnesota Power's draft TOD rate recommendations, alternative rate options, and analysis. The fourth and final meeting was held via webinar on January 11, 2019 and focused on further refined TOD rate design options.

Representatives from Citizens Utility Board, Fresh Energy, Department of Commerce, and the Office of the Attorney General were able to attend all or most meetings either in person or via phone or webinar. 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. All participants received communications and updates prior to and post meetings.

The past TOD Pilot Program learnings and current stakeholder processes are important components of modernizing the customer experience and positioning the Company for business model evolution. The process has provided insight into the desires and needs of Minnesota Power's stakeholders and residential customers, and is a step towards identifying innovative programming that has the potential to optimize system benefits and reduce costs for all customers.

2. OBJECTIVES AND PRINCIPLES

The stakeholders participating in this TOD process spent a substantial amount of time delving into the appropriate principles and objectives under which to develop Minnesota Power's alternative TOD rate designs. The group established two agreed-upon objectives and six "must have" principles as a baseline for the alternative rate design analysis.

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 partly on the opportunity to reduce costs.

“Must Have” Design Principles:

1) Provide an evaluation of the costs and the benefits of the TOD program.
2) Include considerations for indemnifying low-income customers.
3) Enable energy conservation, cost-effective integration of additional renewables, and reduction of greenhouse gas emissions.
4) Provide rates that accurately reflect the costs of energy cost to serve, both now and looking forward.
5) Consider using an opt-out approach for the base TOD rate.
6) Give customers adequate tools to access and understand their usage data.
7)

The full set of design principles, along with further information regarding participant feedback, is outlined in Attachment A of this report.

3. CUSTOMER SURVEYS & ENGAGEMENT

In October of 2018 an online survey from Minnesota Power was promoted to customers through various digital channels, including social media, TOD Pilot Program past and present participants and known electric vehicle owners. The survey was released on October 17, 2018 and closed on November 15, 2018. The Company received 229 (1 Partial) responses[1] to the survey, 111 of which had a past or present connection to the TOD Pilot Program. The responses to the survey are an indication of the preferences and viewpoints of the Company’s highly-engaged customers and may not represent the opinions of the entire customer base. Some high-level observations from the survey include (complete results included in Pages 73-90 of Attachment A):

- Saving money would be the #1 driver for interest in a TOD rate
- 47 percent of customers surveyed are interested in purchasing or currently own an electric vehicle (“EV”)
- 80 percent of customers that responded to the survey are interested in TOD
- Over 90 percent are home owners (vs. renters – not representative of Minnesota Power’s overall customer base)

Minnesota Power also held two in-person customer meetings in its service territory in October; one in Duluth, MN and one in Little Falls, MN. Minnesota Power staff presented information on the Company’s system considerations, resource mix, current residential programs, and general information on demand response programs and Time of Day rates. The meetings drew a small number of customers, however, the customers that did attend were generally engaged and knowledgeable about their energy usage. Key takeaways from the customer meetings included (full summary and presentation included as Attachment B):

[1] Limitations: online only, potentially biased based of how it was conducted and limited ability to “direct market

- Customers seemed to have an understanding of actions they can take to shift usage
- Clear communication and opportunity for savings are key – complex vs. simple rate design wasn't top of mind
- Generally, the customers felt that the CPP events erased opportunity for savings, but were an important tool to incent behavior change
- Savings is a major motivator – with any new rate they would like to see a comparison to current rates

While limitations exist on the information gleaned from this customer feedback experience, the Company believes it was a vital and worthwhile effort. Minnesota Power will perform further customer engagement prior to any future program offering.

III. Meter Data Management and Metering Considerations

Currently, over 50 percent of Minnesota Power's meters in the field are advanced metering infrastructure ("AMI"). Minnesota Power is actively deploying AMI throughout its service territory, largely through meter attrition, at a rate of approximately 6-8 percent (roughly 10,000 meters) annually, continuing over the next several years. Minnesota Power estimates full deployment of all AMI meters by the end of 2025. This schedule could be accelerated if availability of resources (both workforce and funding) are increased. Along with the AMI meter deployment, Minnesota Power completed implementation of its Radio Frequency AMI network communications infrastructure in 2018.

In its May 1, 2018 compliance filing in the docket, Minnesota Power addressed the need for a meter data management ("MDM") solution in relation to a system-wide rollout of a TOD rate. It is important to note that Minnesota Power's planned MDM implementation and integration is a strategic investment for the Company and the continued progress of the MDM system integration does not hinge on the approval or disapproval of a current or future TOD rate. Nevertheless, the fact that Minnesota Power's current method of administering its TOD Rate is not efficient or quickly scalable is one of many learning experiences that drove the Company's decision to invest in a MDM solution. Currently, each meter is manually programmed to recognize the appropriate bucketing of usage relative to the TOD Rate, specifically meters are programmed to look for Total, On, Off, and CPP pricing reads. This is a manual and time-consuming way to administer the program, and one that would constrain a wider rollout of the TOD Rate prior to MDM implementation.

Upon implementation of its MDM system, the Company will have the capability to bill customers utilizing hourly data received from the meters. Usage bucketing according to TOD periods will be handled by the MDM, thereby removing the need for manual custom programming of meters. Consequently, scalability and speed to enroll customers in a TOD rate will increase significantly and the associated cost will decrease significantly. With a MDM in place, it is easier for the meters to communicate their hourly usage rather than the current practice of getting them to recognize and accept a command. This will result in fewer billing issues and far less manual billing interventions. In the current context, the meters bucket all usage and communicate a large daily file back to the Company's customer information system ("CIS"). With a full AMI/MDM established, the hourly data will be transmitted several times a day, which typically equals greater success. A MDM will also allow for flexibility to efficiently change the time periods of a TOD rate. Currently, making a change to the on-and-off peak time periods, or adding additional usage buckets, would require procurement and/or reprogramming of new meters and a meter exchange for every customer placed on the TOD Rate.

There are many benefits associated with a MDM system implementation that go beyond the added functionality needed for a TOD rollout. Benefits of a MDM system include but are not limited to:

- Improved ability to investigate meter and service anomalies using events and alarms.
- Improved power quality detection.
- Better visibility of load data from aggregated meters.
- Increased ability to identify and take action on meter failures and theft.
- Increased integration with outage systems to reduce outage durations, increased accuracy of estimated restoration times, and reduced customer calls to verify power status.
- Promote data-driven decision-making.
- Establish and improve analytics.
- Improved validation.

The Company completed a request for proposal ("RFP") process and MDM selection in late 2018. As a result of its robust RFP process, the Company selected the Oracle Customer to Meter Solution ("Oracle C2M") in November of 2018. The next step in the MDM implementation process is to select a System Integrator ("SI") to assist with the design, build, testing, and implementation of the Oracle C2M solution. The Company currently has an RFP process underway and anticipates SI selection in 3rd quarter of 2019. The presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

IV. Alternative TOD Rate Design Analysis

1. MINNESOTA POWER SYSTEM INFORMATION

In its August 20, 2018, Order Accepting Compliance Report, Postponing Deadline for Next Report, and Requiring Filings, the Commission ordered that Minnesota Power include in this compliance filing, among other things, certain information about its system, including: Minnesota Power's peak demand, Minnesota Power's peak demand consistent with MISO, and the hourly cost of meeting Minnesota Power's peak demand.

For context, the Company's customer mix (measured by sales volumes) differs significantly from that of a typical U.S. electric utility, and even differs from the average customer mix in Minnesota. The U.S. Energy Information Administration ("EIA") reports total electricity sales to ultimate customers in the United States during 2017 were approximately 37 percent residential, 36 percent commercial, and 27 percent industrial. For that same year the EIA reports sales to ultimate consumers in Minnesota as 32 percent residential, 35 percent commercial, and 33 percent industrial.[2] In contrast, the Company's sales volume is almost 75 percent industrial, as shown in Figure 1.

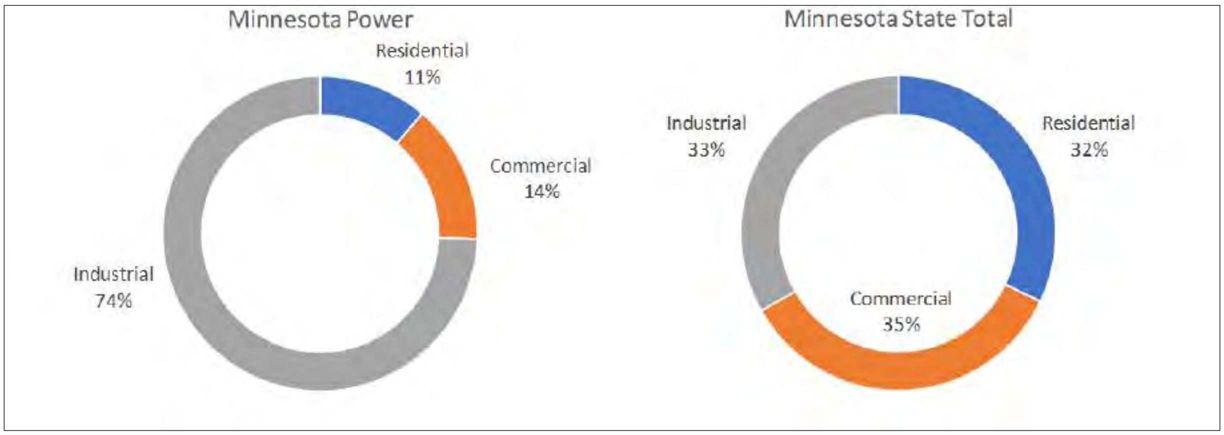

Figure 1: Retail Sales by Customer Class (2017)

a) Minnesota Power Peak Demand

Minnesota Power's system is winter-peaking, with highest demand typically occurring on a winter evening, either in December or in January. Peak demand in 2017 occurred on December 27 at 7:00 PM when system load[3] reached 1,599 MW.

The Company's predominantly industrial sales mix results in a very high load factor with much less daily and monthly variability than a typical utility. Figure 2 below shows the monthly system peak demand projected for the year 2020, reflecting expected peak demand under normal weather conditions. As shown in Figure 2, the Company's peak demand during the summer is forecasted to reach 1,597 MW in July 2020, which is about 1.5 percent lower than the January

[2] https://www.eia.gov/electricity/data/eia861/

[3] Net of customer-owned generation

2020 peak of 1,622 MW. Furthermore, the lowest projected monthly peak in 2020 is 1,455 MW (in May 2020), more than 10 percent lower than the winter peak.

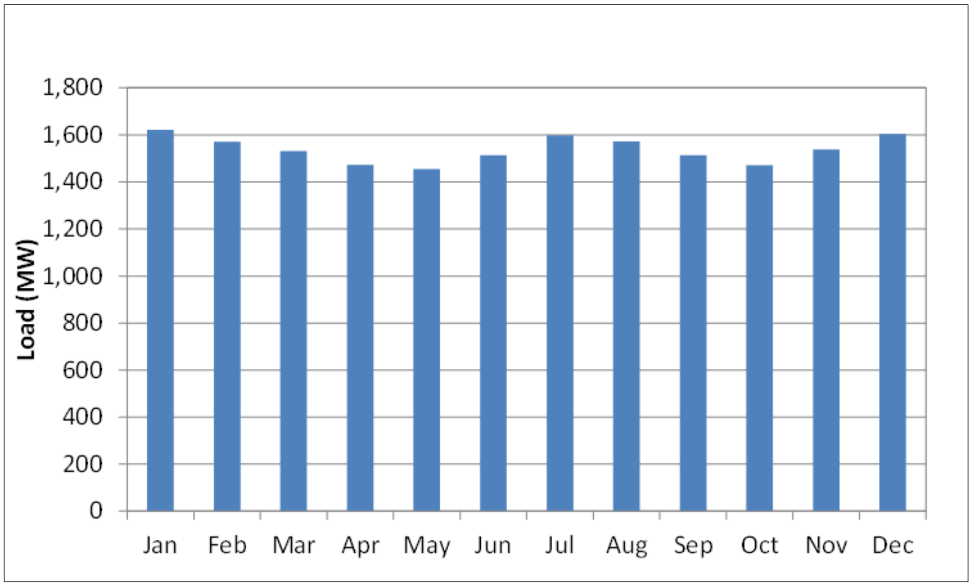

Figure 2: Minnesota Power System Peak Demand by Month 2020 Weather Normalized

It is also notable that the summer system peak typically occurs earlier in the day, in the afternoon, compared to the evening winter peak. Figure 3 below illustrates the daily system load profile for the summer and winter peak days.

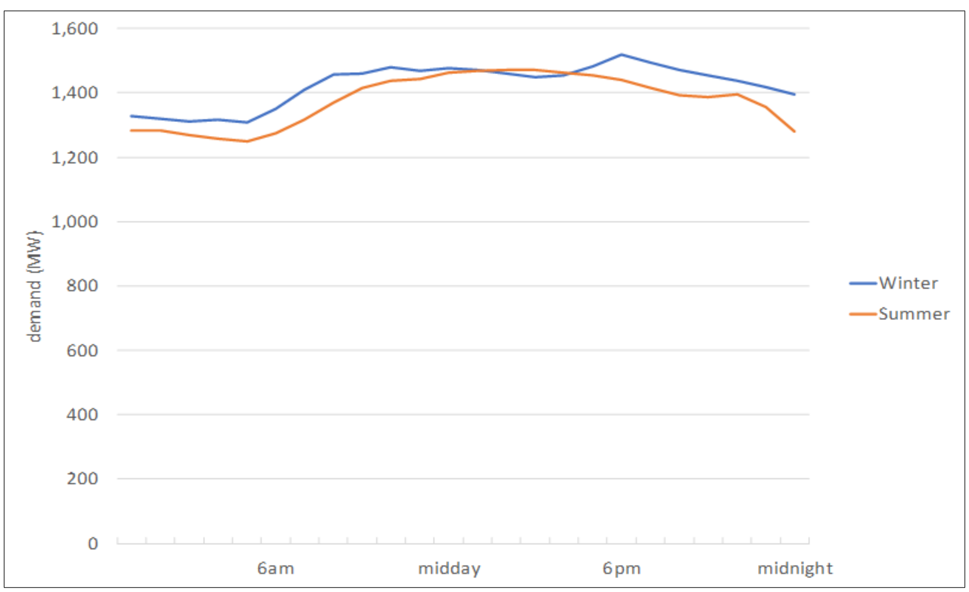

Figure 3: Minnesota Power Daily System Load Profile 2020 Peak Winter and Summer Days

As expected, the Company's residential demand exhibits much more variation than the total system demand profile, both over the course of a year and throughout the day. Similar to the system peak, residential peak demand is highest in the winter.

The daily load profile of the Company's residential customers is similar during the winter and summer seasons, with peak demand occurring in the evening hours. Figure 4 illustrates the daily residential load profile for the summer and winter peak days.

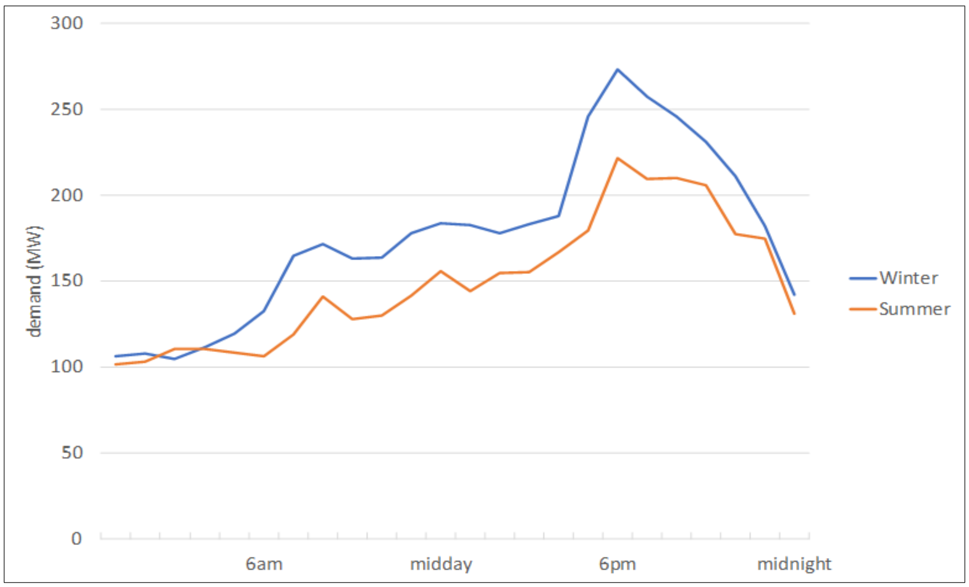

Figure 4: Minnesota Power Daily Residential Load Profile 2020 Peak Winter and Summer Days

b) MISO Peak Demand

Minnesota Power's system sits within MISO Load Resource Zone 1 ("LRZ1") which, in addition to most of the state of Minnesota, encompasses western Wisconsin, north-eastern South Dakota, North Dakota and eastern Montana. Minnesota Power accounts for approximately 10 percent of LRZ1 load.

In contrast to Minnesota Power, MISO LRZ1 is a summer-peaking zone, with the highest demand occurring on a summer day in late afternoon. Across the year LRZ1 load shows more variability than Minnesota Power load, reflecting the more typical load mix (with more residential and commercial load) in LRZ1. Winter peak demand for LRZ1 is approximately 10 percent below summer peak demand.

Figure 5 on Page 11 shows that peak demand in MISO LRZ1 approached 17,000 MW in July 2017.

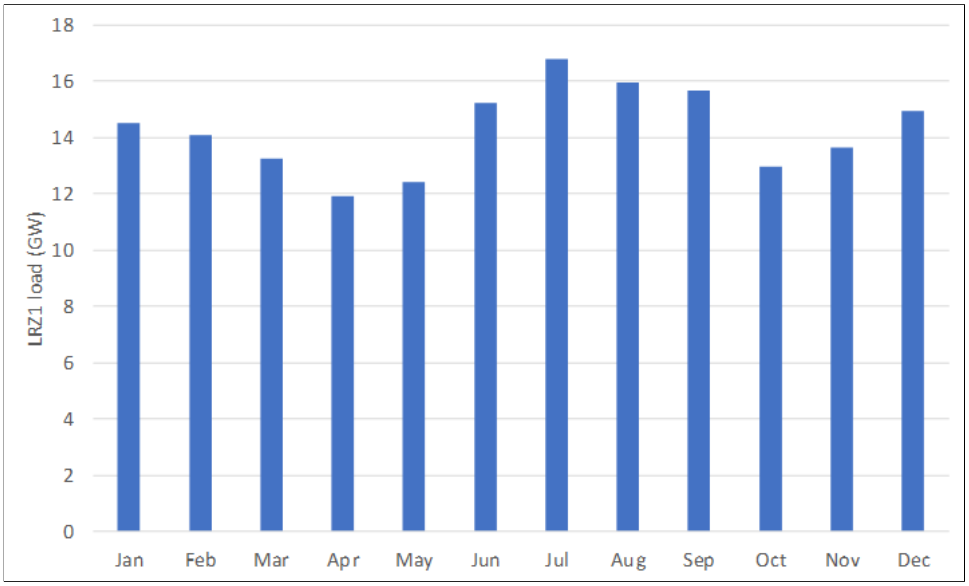

Figure 5: 2017 MISO LRZ1 Peak Demand by Month

Both Minnesota Power's and MISO LRZ1's load profiles differ by season. Figure 6 below illustrates the MSIO LRZ1 daily load profile for the 2017 summer and winter peak days. Summer days exhibited the traditional afternoon ramp into the evening peak hour, while the winter peak day tends to have a dual peak profile, with relatively higher demand in the morning and evening hours.

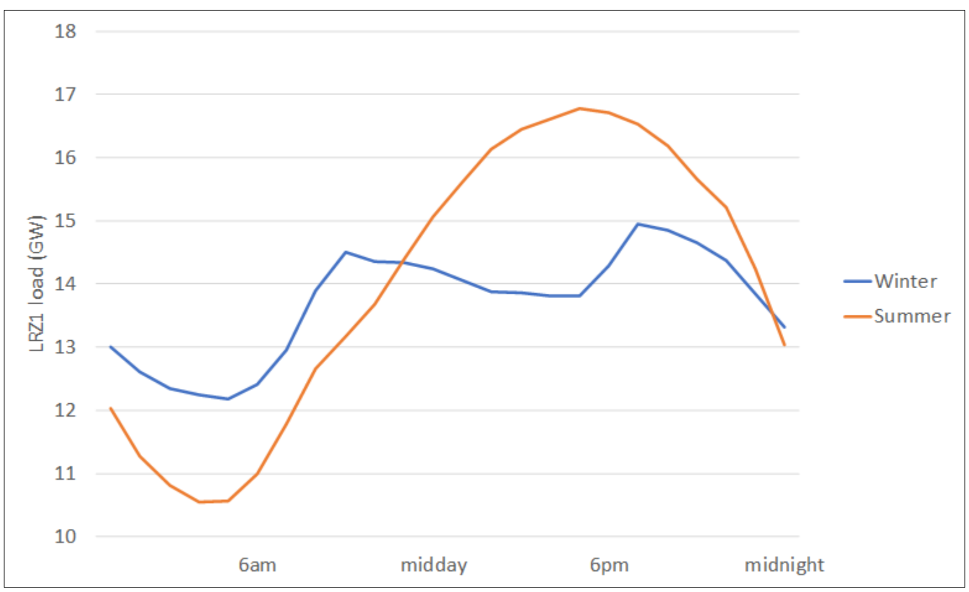

Figure 6: 2017 MISO LRZ1 Profile of Peak Winter and Summer Days

Figure 7 below overlays the Minnesota Power load profile on the MISO LRZ1 profile for July 6, 2017, the peak LRZ1 load day in 2017. MISO LRZ1 load peaked in the hour ending 5:00 PM. On that day Minnesota Power's load peaked at 1,476 MW in the hour ending 4:00 PM (one hour ahead of the LRZ1 peak). Minnesota Power's daily peak of 1,476 MW was 8 percent below its own 2017 system peak of 1,599 MW (which occurred in December). Within the day, the load shapes of LRZ1 and Minnesota Power are broadly aligned; however, the impact of Minnesota Power's concentration of industrial customers creates a flatter load profile.

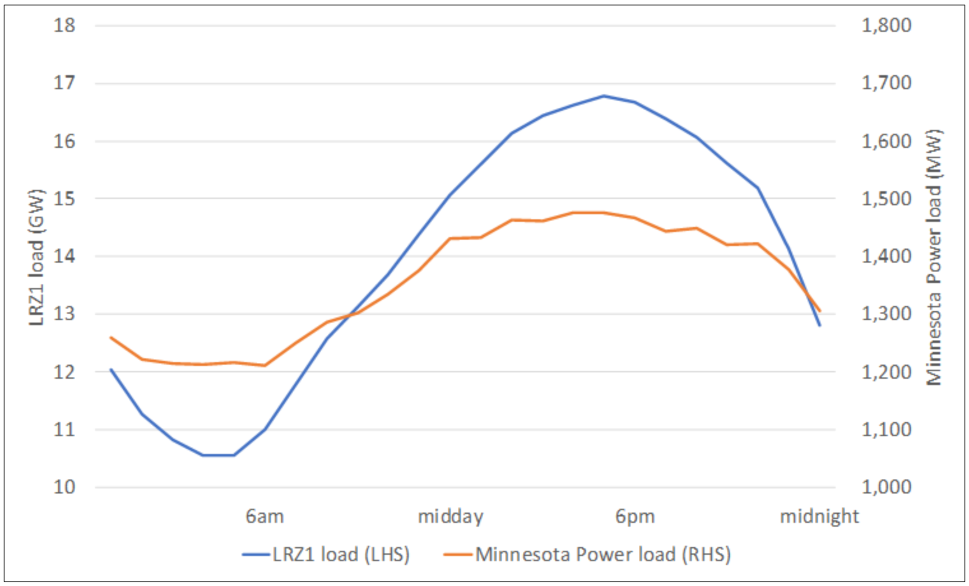

Figure 7: MISO LRZ1 Peak Day Load Profile with Minnesota Power Overlay July 6, 2017

2. HOURLY COST OF SERVING SYSTEM DEMAND

a) Overview of Approach

Many of the costs of serving electric utility customers, for example the fixed infrastructure costs of network and generation assets, are not incurred or observed on an hourly basis. Consequently, to calculate the hourly cost of serving peak demand, Navigant Consulting developed an approach for converting annual costs from the Company's general rate filing into hourly amounts.

The annual costs to serve residential customers were last reviewed in the Company's 2016 general rate case filing and new rates were approved by the Commission on May 29, 2018.[4] In its June 28, 2018 Compliance Filing the Company submitted its electric class cost-of-service study reflecting the Commission's Order; the cost-of-service study classified costs as being either

[4] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, May 29, 2018, Order Granting Reconsideration in Part, Revising March 12 2018 Order, and Otherwise Denying Reconsideration Petitions.

capacity-, energy-, or customer-related. The study further allocated the approved test year costs to the Company's various customer classes.

Table 1 shows the Commission-approved annual revenue requirement allocated to the residential customer class, broken down into capacity, energy, and customer classification. Table 1 also identifies the approach used to allocate each cost classification across the hours of a year.

Table 1: Revenue Requirements[5]

Classification	Hourly Cost Allocation	Annual Cost
Capacity	Cost Duration Method	\$47m
Energy	Locational Marginal Prices	\$31m
Customer	Evenly Allocated	\$27m
Total Revenue Requirement		\$105m

To convert the annual revenue requirement into an hourly cost to meet demand, the Company allocated annual dollars to each hour during the year using a specific method for each cost classification. For example, capacity costs were determined to be driven by the need to serve the next increment of demand and were allocated to each hour using the Cost Duration Method, discussed in detail in Section 2.b.

Annual energy costs were allocated to each hour based on the hourly locational marginal price ("LMP") at the MISO Minnesota Power ("MP") node. Figures 8 and 9 on Page 14 summarize the MISO MP prices projected for 2020, illustrating the seasonal price fluctuations as well as the daily shape during the winter and summer seasons.

[5] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, Compliance Filing dated June 28, 2018, Compliance Schedule 11, page 104 of 104

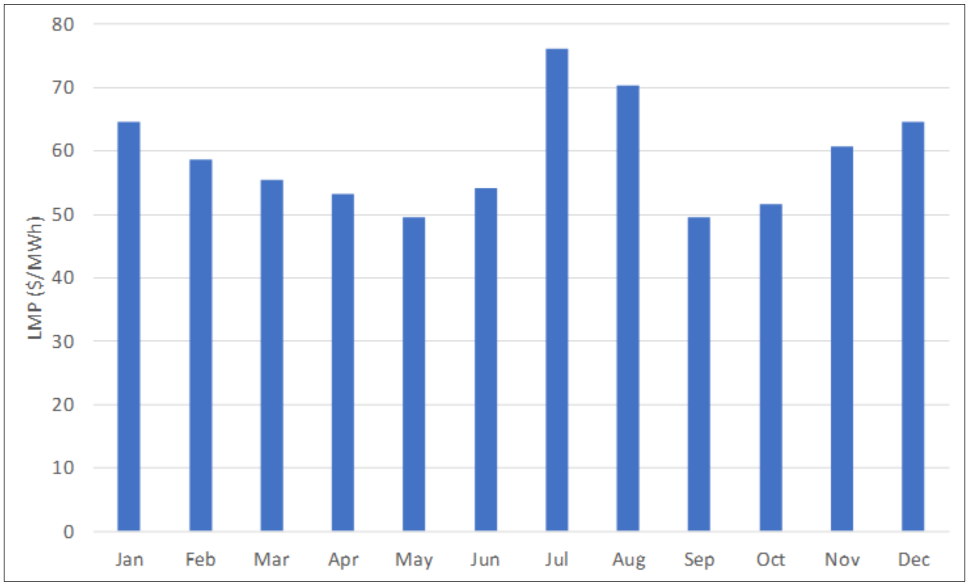

Figure 8: Maximum MISO MP LMP by Month

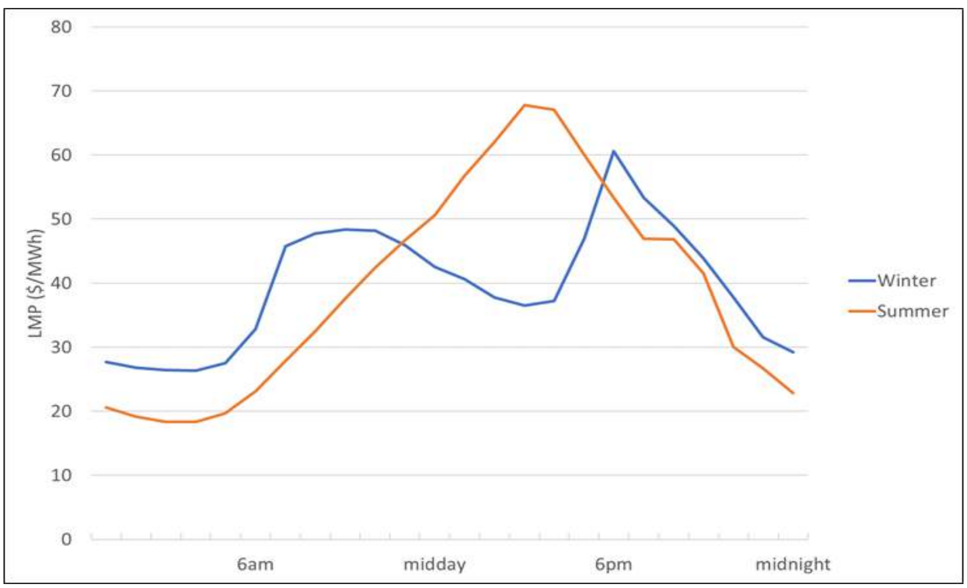

Figure 9: MISO MP Typical Daily LMP Profile by Season

Customer costs (such as metering and administration costs) are fixed costs that are not impacted by level of demand or load on Minnesota Power's system. The Company's residential rates include an $8 per month service charge which covers approximately $11 million of the $16 million annual customer costs. The remaining $5 million of customer costs were allocated evenly across all 8,760 hours of the year.

b) Cost Duration Method

Close examination of a utility's load duration curve (such as Minnesota Power's residential load curve in Figure 10) reveals several features. For example, it's clear some assets are only used to meet demand during a small number of "peak" hours. Thus, it would be appropriate to assign a significant share of costs for these peaking assets to the hours that rank highest on the load duration curve. Similarly, there is a minimum load or "baseload" demand which all hours of the year exceed. Thus, there is some portion of costs which should be assigned equally to all 8,760 hours of the year.

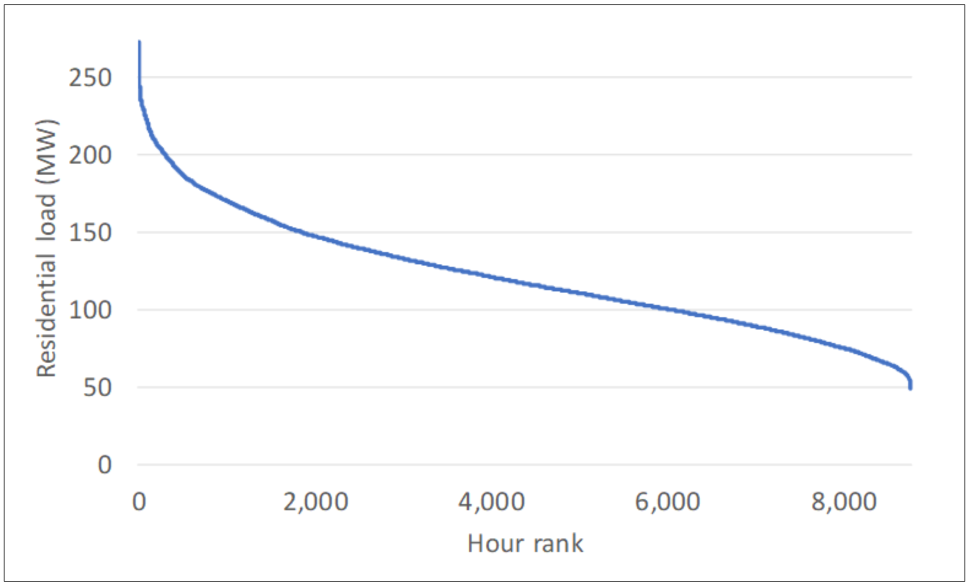

Figure 10: Minnesota Power Residential Load Duration Curve

Navigant Consulting developed a cost duration method designed to capture these features by assigning a share of costs to each hour in a way that reflects the usage as illustrated by the load duration curve. The assignment of costs to specific hours can be further categorized through the steps outlined in the next section.

The Company's capacity costs should be identified at the functional level, i.e. generation, transmission, and distribution because demand for generation, transmission, and distribution capacity is not perfectly coincident. Table 2 on Page 16 breaks down the capacity costs from the Company's electric cost of service study into the respective functions.

Table 2: Minnesota Power Residential Capacity Costs by Function

Function	Annual Cost
Generation	$21m
Transmission	$7m
Distribution	$19m
Total Capacity Cost	**$47m**

For each capacity cost type, specific load duration curves were used to allocate costs across the hours of the year:

- The MISO LRZ1 load duration curve was used to allocate generation capacity costs; the Company's generation capacity requirements (imposed by MISO) are driven by its load during MISO's highest peak demand hours. As described above, peak demand in MISO LRZ1 occurs during different hours than Minnesota Power's native peak demand.
- Minnesota Power's system load duration curve was used to allocate transmission capacity costs; the Company's system load drives the need for new transmission capacity.
- Minnesota Power's residential load duration curve was used to allocate distribution capacity costs; the Company's residential load is the best indicator of distribution capacity requirements in residential areas.

The following steps detail application of the cost duration method to the distribution capacity costs, and the same process was followed with respect to the generation and transmission functions.

Step 1: Calculate the unit cost of capacity

Capacity costs are divided by the peak load of each load duration curve to find a unit cost per MW of capacity.

For example, distribution capacity costs are $19 million and residential peak demand is 273 MW, giving a distribution capacity unit cost of $68,363 per MW.

Step 2: Calculate the incremental load in each hour

The incremental load in each hour is calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is used. Note that the sum of all these incremental load amounts is equal to the peak load.

For example, for distribution capacity the load in the hour with the highest load is 8 MW higher than the second highest hour, which is in turn 6 MW higher the third highest hour, which is in turn 2 MW higher the fourth highest hour, and so on. The lowest load hour has load of 49 MW.

Step 3: Share the incremental load across higher hours

For each hour, the incremental load is shared evenly between the hour in question and all hours of the year that have a higher load than the hour in question. The incremental load at the highest load hour is not shared as there are no higher load hours. The incremental load at the second highest hour is shared evenly between the top two hours, so each gets a one-half share.

For distribution capacity, the 8 MW incremental load in the highest load hour is allocated only to that hour. 3 MW of the 6 MW incremental load in the second highest hour is allocated to that hour and the other 3 MW is allocated to the highest load hour. The 2 MW incremental load in the third highest hour is shared across the top three hours, and so on.

Step 4: Total the load allocated to each hour

The load allocated to each hour is then totaled. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so on.

For distribution capacity, totaling all the load allocated to the highest load hour (8 MW plus 3 MW plus 2/3 MW plus…) gives 14 MW, for the second highest hour (3 MW plus 2/3 MW plus…) gives 7 MW, and so on for each hour.

Step 5: Calculate the total and unit cost of each hour

The load allocated to each hour in Step 4 is multiplied by the unit cost calculated in Step 1 to calculate the total cost of each hour. This can in turn by divided by the billing load in that hour to calculate the unit cost of each hour.

As illustrated in Figure 11 below, the costs are spread to each hour in a manner that closely resembles the load duration curve and therefore reflects system use. This spread of costs to each hour is known as the "Cost Duration Curve."

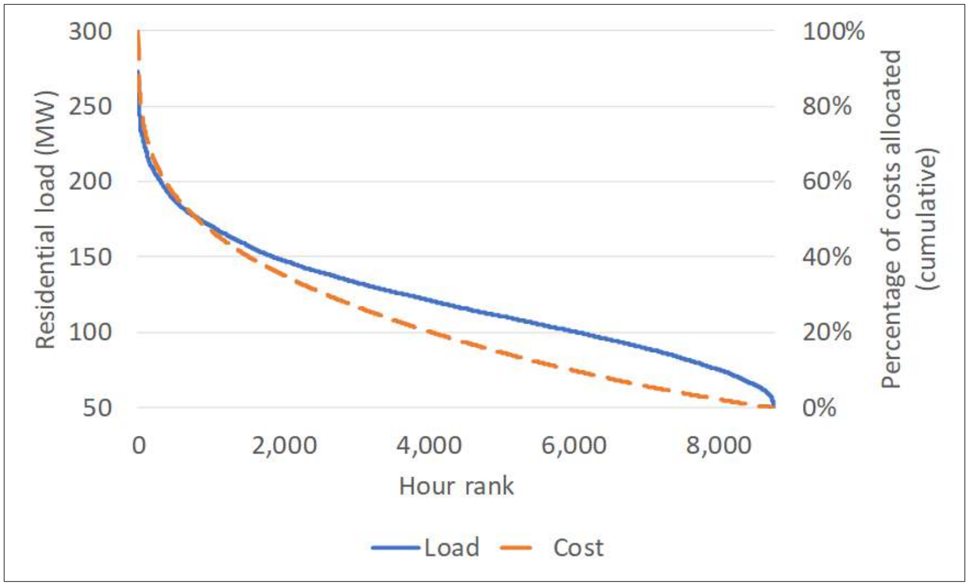

Figure 11: Residential Load and Distribution Capacity Cost Duration Curves

c) Hourly Cost of Serving System Demand

Combining the results of the cost duration method calculations described above for capacity costs with hourly energy costs provides the variable cost of serving residential demand in each hour of the year. Figure 12 shows the hourly costs and illustrates the relative magnitude in each hour.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	5.6	5.6	5.3	5.1	5.5	5.7	5.2	5.4	5.0	5.3	5.5	5.5
	5.4	5.5	5.2	5.1	5.5	5.8	5.2	5.4	5.0	5.4	5.4	5.4
	5.3	5.4	5.2	5.1	5.5	5.8	5.1	5.4	5.0	5.4	5.4	5.3
	5.2	5.4	5.2	5.1	5.7	5.8	5.2	5.4	5.1	5.5	5.4	5.2
	5.3	5.4	5.4	5.6	5.9	5.9	5.2	5.5	5.4	5.9	5.6	5.3
6am	5.9	6.0	6.2	6.3	6.2	6.2	5.4	5.7	5.7	6.6	6.0	5.7
	7.4	6.9	7.1	6.7	6.5	6.5	5.8	6.1	6.2	6.6	6.5	6.7
	8.2	7.5	7.5	6.8	6.7	6.7	6.3	6.4	6.4	6.8	6.8	7.5
	8.9	7.9	7.6	7.0	6.9	7.1	6.9	6.7	6.7	6.9	7.1	7.9
	8.8	7.8	7.6	6.9	7.0	7.4	7.6	7.0	7.0	7.0	7.1	8.5
	9.3	7.5	7.4	6.7	7.0	7.8	8.6	7.4	7.1	6.9	7.0	8.1
midday	8.5	7.4	7.1	6.5	6.9	8.2	9.9	7.9	7.3	6.8	6.9	8.0
	8.0	7.1	6.8	6.5	6.9	8.7	12.0	8.5	7.6	6.8	6.7	7.9
	7.4	6.8	6.6	6.4	7.0	9.3	15.3	9.4	8.2	6.8	6.6	7.5
	7.1	6.6	6.4	6.3	7.0	9.8	19.0	10.1	8.7	6.8	6.5	7.1
	7.4	6.5	6.4	6.2	6.9	10.2	21.7	10.1	8.8	6.7	6.4	7.4
	9.9	6.9	6.4	5.9	6.6	9.9	25.8	9.5	8.7	6.6	7.5	11.2
6pm	17.3	8.9	7.1	5.8	6.3	9.4	24.7	9.0	8.3	7.4	8.9	33.0
	17.9	9.1	8.1	6.6	6.4	8.7	18.4	8.3	7.9	7.1	8.5	29.9
	15.6	9.0	8.3	6.7	6.6	8.2	14.0	7.9	7.3	6.4	7.8	17.8
	10.5	7.8	7.4	5.9	6.1	7.5	10.3	7.2	6.8	5.9	6.9	12.4
	8.2	6.8	6.4	5.3	5.7	6.7	7.9	6.3	5.9	5.6	6.3	9.4
	6.5	6.2	5.5	5.1	5.5	6.2	6.1	5.7	5.1	5.3	5.9	6.9
midnight	5.9	5.8	5.2	5.0	5.4	5.8	5.4	5.5	4.9	5.3	5.6	5.8

Figure 12: Hourly Variable Cost by Month of Serving Residential Load (c/kWh

Highest cost hours (shaded red) occur in two distinct periods:

- Winter evenings, particularly in December and January, and
- Summer afternoons, particularly in July.

The high-cost winter evening hours reflect the high demand on Minnesota Power's transmission and distribution systems, as well as moderately high LRZ1 system demand and LMPs. The high-cost summer afternoon hours reflect high demand in LRZ1 and high LMPs, as well as moderately high demand on Minnesota Power's transmission and distribution systems.

Lowest cost periods (shaded green) mostly occur overnight and reflect the combination of low demand across LRZ1 and Minnesota Power's systems, and low LMPs.

Costs vary significantly between hours, with the cost to serve load in highest cost hours being up to six times higher than in the lowest cost hours. This variance, while significant, is not at large as other utilities' where times of high system demand and high LMPs are more closely aligned.

3. ALTERNATIVE RATE DESIGNS AND TOD PERIODS

Minnesota Power has offered its current TOD Rate as a pilot program since 2014. This time-of-day rate has been in the form of an adder, or extra charge, on kilowatt–hours (kWh) of energy consumed during "on-peak" hours—defined as 8:00 a.m. to 10:00 p.m. on weekdays, excluding holidays—and a discount on kWh usage during off-peak hours, which are all hours outside of on-peak hours (as depicted in Table 3 below). The rate also includes the option for the Company to declare up to 50 hours per year of Critical Peak Pricing Events during pre-specified time windows, with an adder of 77 cents per kWh applying during these events.

Table 3: Current Rate Structure

Current Rate Structure May 2017 - Present	
On-Peak Hours	08:00 - 22:00 Monday - Friday
Off-Peak Hours	All other hours & designated Holidays
Summer CPP Hours	12:00 - 15:00
Winter CPP Hours	17:00 - 20:00
On-Peak Increase	$0.0487
Off-Peak Discount	-$0.0299
CPP Event Increase	$0.77

a) Approach to designing TOD rates

A core principle of any rate design is to ensure the rates being charged to customers reflect cost causation. When developing a TOD rate, a methodology should be utilized to align prices charged during each TOD period with the costs incurred during the same period. This alignment is intended to accomplish two goals:

1. Ensure rates for each TOD period reflect the cost of meeting demand at those times (i.e. cost causation), and
2. Send a time-differentiated price signal to customers to encourage peak demand reduction.

Constructing TOD rates from hourly costs

TOD rates can be directly derived from the hourly variable costs of serving load shown in Figure 13 on Page 23. Once the TOD time periods have been selected (discussed below), the weighted average of the costs of each hour within each TOD period is calculated. The billing unit (i.e. residential kWh) associated with each hour is used to weight the hourly costs, so higher load hours are weighted more heavily than lower load hours. The remaining portion of customer costs not recovered via the monthly service charge is then added to this weighted average variable cost to calculate the TOD rate.

The TOD rate is initially calculated as a stand-alone rate, but the Company must convert it to the adder/discount structure utilized in the Company's TOD pilot program using the current residential tariff rate as the baseline in order to accommodate the existing inverted block rate ("IBR") structure (more discussion surrounding IBR vs flat rates can be found on Page 26 of this filing).

Preliminary TOD periods

Selecting TOD periods requires balancing a number of different goals such as simplicity for customers (and the utility) and desired size of price differentials between time periods. A peak period narrowly targeted at highest costs hours, such as one that only applies for a small number of (potentially differing) hours during a small number of months, will lead to sharp pricing differentials but may be more challenging for customers and the utility to manage. In contrast, a more broadly targeted peak period, such as one that applies for a larger number of hours year-round, will lead to more muted pricing differentials but may be more appealing to customers.

The Company developed two preliminary TOD period options and associated rates that contrasted in their degrees of targeting and simplicity. The TOD periods were reviewed and refined through the stakeholder process. Through that process the Company developed the set of preferred TOD rate design alternatives that are included in this filing.

Preliminary Option 1 was a targeted peak period option with higher associated peak prices. Peak periods were targeted at hours where the cost to serve was more than 1.3 times the average cost to serve, resulting in peak periods of four hours in length, with the timing of these periods varying between winter (5:00 PM – 9:00 PM) and summer (3:00 PM – 7:00 PM). In the shoulder seasons, spring and fall, there were no peak periods, i.e. off-peak rates applied all day.

Preliminary Option 2 had longer peak periods and relatively lower peak prices. Peak periods applied year-round and were six hours in length so that they covered key high-cost hours in both winter and summer.

For both options the Company employed a three-period structure with peak, off-peak, and super off-peak time periods. Peak periods applied on weekdays only. Super off-peak prices applied overnight throughout the year. The three-period structure allows the Company to target both high-cost and low-cost time periods, which is not possible under a two-period structure that can typically target only one or the other.

b) Stakeholder Feedback on Proposed Rates

Stakeholder feedback on the Company's approach and preliminary options was generally positive. Commenters supported the three-period rate structure and noted that the rates generally seemed well-aligned with underlying costs.

When compared with the Company's existing TOD Rate, stakeholders liked the shorter, more targeted, peak periods which they felt would better enable customer load shifting response. They also felt excluding the Critical Peak Pricing Events made the options simpler, and therefore more favorable, than the current pilot Rate. While the Company agrees the inclusion of a CPP component adds complexity, Minnesota Power would like to note that it also allows for a deeper discount during normal on-peak/off-peak hours by shifting more substantial costs to fewer targeted hours of the year. The trade-off is that customers may be less impacted by day-to-day peak time usage but only realize the benefits of being on a TOD rate if they are able to make substantial changes during CPP event periods. System benefits of the more targeted (but limited) higher cost periods were not evaluated as part of this process so it is not clear how such a structure would impact system efficiencies in comparison to the three-period peak structure explored in this analysis.

Stakeholders provided several suggestions for adjustments to the preliminary options. While they liked the targeted approach of Preliminary Option 1, they felt that having three distinct time periods for summer, winter and shoulder seasons was not customer-friendly and suggested exploring options with only two seasons.

On Preliminary Option 2, commenters felt that the six-hour peak period did not produce rates with sufficient differential between the time periods and suggested reducing the length of peak period to increase the rate differentials. Pages 91-105 of Attachment A to this filing provide examples of rates developed through the stakeholder/analysis process that were ultimately not selected.

Finally, stakeholders suggested looking at ways to reduce the super off-peak price, potentially by shortening the length of the super off-peak time period.

c) Final Preferred Alternatives

Based on this stakeholder feedback, the Company has produced three preferred TOD rate design alternatives.

Table 4: Preferred TOD Rate Design Options - Average Prices (c/kWh)

	Option 1	Option 2	Option 3
Peak	16.8	13.8	14.9
Off-peak	9.2	9.2	9.2
Super off-peak	6.7	6.7	6.7

Table 5: Final Rate Design Options – Time Periods

	Option 1	Option 2	Option 3
Peak	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep	3:00 PM – 8:00 PM weekdays	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	All other times	All other times	All other times
Super off-peak	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM

Option 1

The rates and time periods for Option 1 are shown in Table 6 and Figure 13 on Page 23.

Table 6: Option 1

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	16.8	7.2	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep
Off-peak	9.2	-0.4	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

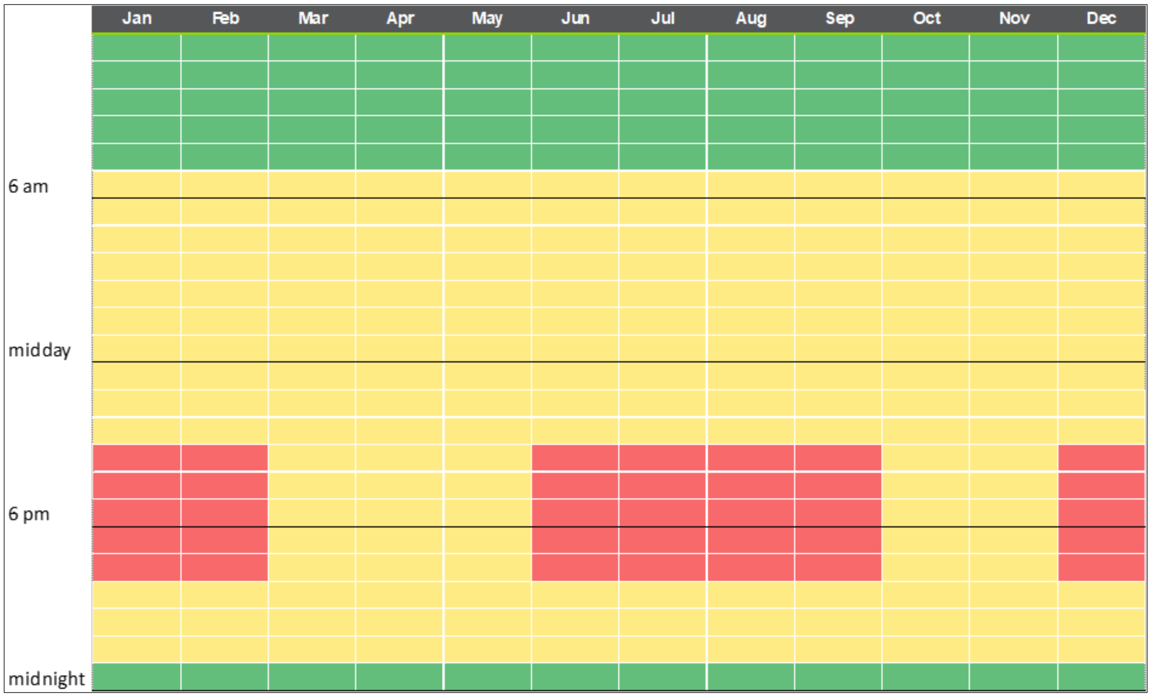

Figure 13: Option 1 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 1 was developed from the Preliminary Option 1 presented to stakeholders. It includes two seasons:

- A ‘high’ season with a five-hour peak period from 3:00 PM to 8:00 PM, that applies in seven months (December to February and June to September), and
- A ‘low’ season with no peak periods, that applies in five months (Mar to May and October to November).

The ‘low’ season with no peak time periods targets the low cost to serve those months of the year. This in turn ensures that peak periods are better targeted towards high cost times and drives a significant price differential between time periods.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

For customers, Option 1 provides the fewest hours with peak prices of the three options and provides the highest potential to save money by shifting load out of peak periods.

Option 2

Table 7: Option 2

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	13.8	4.3	3:00 PM – 8:00 PM weekdays
Off-peak	9.2	-0.3	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

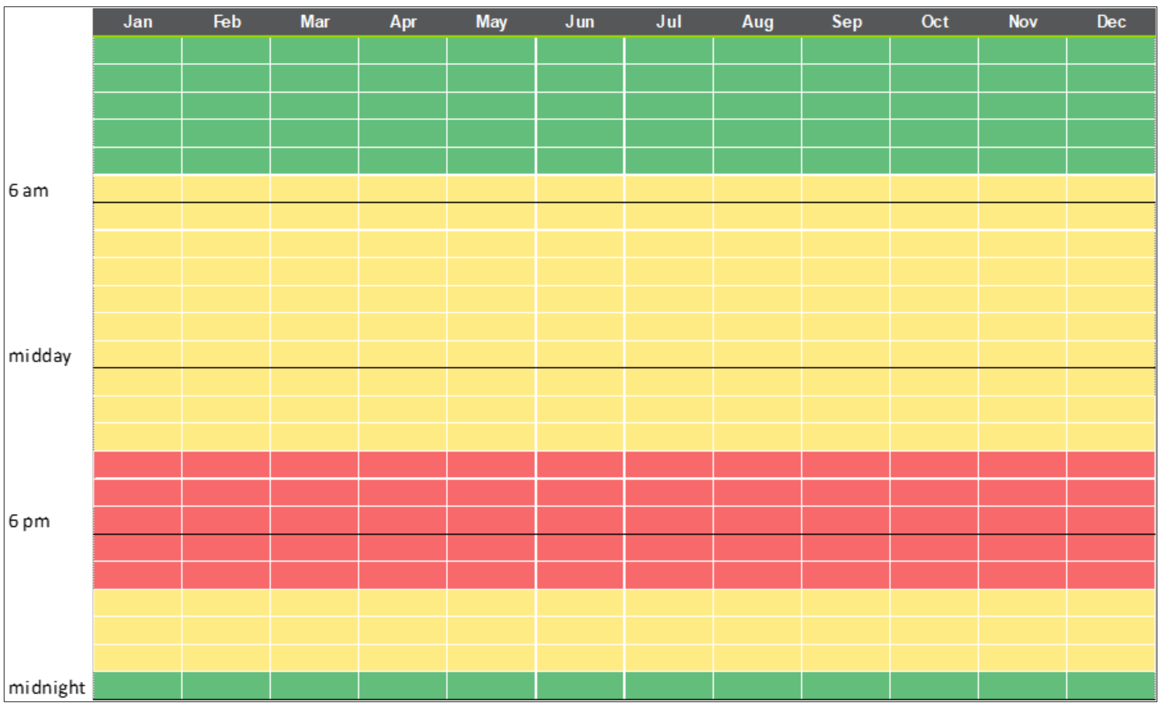

Figure 14: Option 2 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 2 was developed from the Preliminary Option 2 presented to stakeholders. It includes a five-hour peak period year-round from 3:00 PM to 8:00 PM, reduced from six hours under the preliminary option. The five-hour length of the peak period is the shortest possible year-round period that still captures key high-cost hours in both winter and summer.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

Option 2 is the simplest option from a customer perspective. The time periods do not change during the year, enabling customers to adopt a single load shifting approach. The trade-off is that the peak time period is the least targeted of the three options, so the price differential across time periods is muted.

Option 3

The rates and time periods for Option 3 are shown in Table 8 and Figure 15 below.

Table 8: Option 3

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	14.9	5.3	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	9.2	-0.2	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

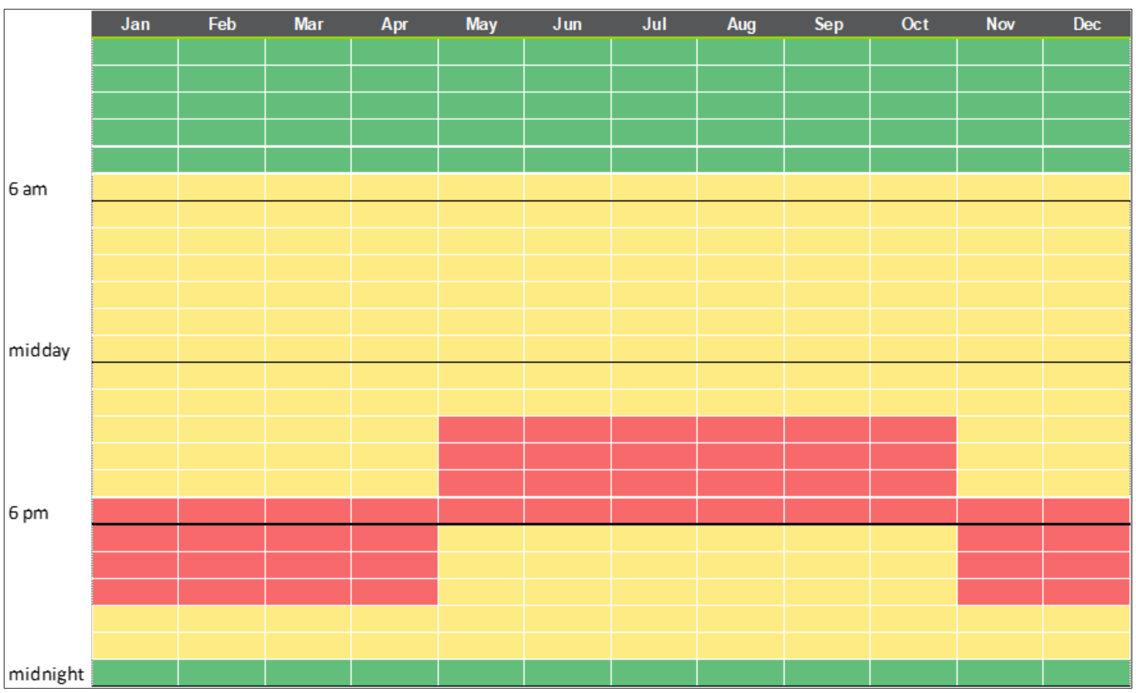

Figure 15: Option 3 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 3 was developed from the Preliminary Option 1 presented to stakeholders. It includes two seasons:

- A ‘winter’ season with a four-hour peak period from 5:00 PM to 9:00 PM for six months, and
- A ‘summer’ season with a four-hour peak period from 2:00 PM to 6:00 PM for six months.

The staggered timing of winter and summer peak periods ensures that high cost hours in the winter evening and late summer afternoons are both covered by peak periods.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

For customers, Option 3 provides an intermediate option between Options 1 and 2: it maintains year-round peak periods but tightens the timing of the peak periods, making them more targeted to high cost hours, increasing the price differentials.

d) Commentary on Price Differentials

The three preferred TOD options do not exhibit as large a price differential between peak and super off-peak prices as seen in TOD rates of many other utilities. There are several contributing reasons for this. First, as outlined in Section IV.1.a, the Company’s system has a very high load factor with little seasonal or hourly load variability. This means that transmission capacity costs are shared relatively evenly over many hours which in turn flattens the rate structure.

Second, as outlined in Section 1.b, the Company’s system is winter-peaking but sits within the summer-peaking MISO LRZ1 zone. The times of highest MISO energy prices and capacity requirements do not coincide with times of highest demand on the Company’s system, leading to a flatter rate structure than if they did coincide.

Finally, as noted in Section 2.a, the Company’s monthly service charge is not sufficient to recover all customer-related costs. Some of these customer-related costs must therefore be recovered through TOD rates, which increases the rates in all periods, thereby reducing the relative differential.

e) Inverted Block Rates and Effect on Dynamic Pricing

Designing TOD rates within Minnesota Power’s current residential rate structure of Inclining Block Rates (IBR) is complex and requires converting the TOD rates from stand-alone rates to adders/discounts as outlined in Section 3.a of this report. Minnesota Power’s standard residential rates currently include four separate blocks, or levels of energy usage, with increasing prices for each successive 400 kWh increase in monthly energy usage. If Minnesota Power were to offer a flat TOD energy rate as an alternative to the standard rate, higher-usage customers who currently pay the highest block rate (14.653¢/kWh for usage above 1,200 kWh per month) would likely benefit from switching to the flat TOD rate. In contrast, lower-usage customers who pay the lowest rate (7.423¢/kWh for usage below 400 kWh per month) would likely pay more on a flat TOD rate, even during off-peak hours.

While IBR are considered by some stakeholders as a method of rate design that can encourage energy conservation and improve affordability for low-usage customers, Minnesota Power in previous annual reports to the Commission on its IBR has been unable to conclude their effectiveness as incentive for energy conservation and as an equitable rate structure for its customers.[6] IBR by definition establishes monthly kWh energy usage levels and applies energy rates that progressively increase with each usage level. The level at which the rate blocks are set can lead to decreases in bills for some customers while significantly increasing others, and are more policy-based than cost-based. Customer affordability may not be materially affected by IBR because total monthly energy use correlates poorly to income and is more affected by other factors such as household size and the energy source used for household appliances. Additionally, in an energy future that would encourage decarbonization through smart integration of renewable energy, IBR serves as a disincentive to customers to select electric fueled home appliances over alternatives. Overall, the issue of using rate design as a conservation incentive requires critical evaluation and analysis of all related factors.

Time-based rate design has an advantage over IBR by more accurately representing time variations in the cost of energy. This will be especially true as the industry begins to face new challenges associated with anticipated changes in resources on the grid. On a TOD rate, customer bills do not change based primarily on the amount of energy used each month, but vary mainly by the time when energy is used. This more closely matches utility energy supply cost variations by season or month of year, day of week, and time of day. IBR, on the other hand, provide a less effective cost signal by recognizing only total monthly energy usage in place of actual cost differences. Building a TOD rate on top of IBR makes the rate design more complex, resulting in price signals and bill impacts that are more difficult to understand, and the effectiveness of the rate design may therefore be diminished. As an example, a customer who purchases an electric vehicle and charges their vehicle solely off-peak is theoretically providing benefits to the system, yet with an IBR, that customer will be penalized because that increased off-peak usage will place the customer in a higher/more expensive IBR tier.

As mentioned in Section I of this report, Minnesota Power does not consider the rate alternatives presented in this filing as final and will continue to evaluate the billing impact of opt-out or system-wide TOD rate offerings built on both its current IBR structure as well as compared to a flat rate or other standard residential rate designs that may be approved by the Commission in the future.

[6] In the Matter of Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-015/GR-09-1151, Annual Block Rate Compliance Filings dated January 11, 2013; April 28, 2014; May 5, 2015; July 26-2016, and December 20, 2017.

f) TOD Rates and Customer Generation

Another potential complexity associated with a broader TOD rate offering is how billing on TOD rates would interact with billings and credits for customers with self-generation. The Company is still investigating the metering and billing challenges of implementing TOD rates for a customer with self-generation, such as rooftop solar, which exports energy to Minnesota Power. Initial investigations point to implementation challenges. Minnesota Power's Rider for Parallel Generation has compensation options including the Company's average retail energy rate, simultaneous purchase and sale rate, and time-of-day purchase rate that apply to cogenerators and small power producers rated at 40 kW or less. If technical barriers prove overly arduous, or the costs excessively prohibitive, the Company may consider a single export rate linked to its average retail rate but cannot commit to such a structure absent further investigation. A single export rate arrangement would, however, avoid having to input two or three different prices that change by season and tier. The sheer combination of four standard residential energy rate tiers plus three different daily prices with possible seasonal changes to time periods is not only challenging from a metering and billing perspective but also for customer comprehension and installer economic modeling. The Company will continue to evaluate the programming options available for net metering and other distributed generation customers that may be achievable with the implementation of the MDM.

V. Customer Bill Impacts

Stakeholders communicated very clearly that bill impacts are a serious concern for some customer classes when considering implementation of a TOD rate. The Company has completed preliminary bill impact assessments and examples to give stakeholders and the Commission a cursory representation of how these preferred rate options would affect customers' bills.

A sample of hourly AMI energy use data from Low-Income Home Energy Assistance Program ("LIHEAP") and non-LIHEAP residential customers for a one-year analysis period shows these customers tend to use energy at the same times of the day. The table below shows how similarly LIHEAP and non-LIHEAP customers use energy; under any of the three TOD rate options, the share of energy usage during the on, off, and super-off peak periods are nearly identical. LIHEAP customers do tend to use a greater share of their energy during on-peak periods than non-LIHEAP customers, but they also tend to use more in the super-off peak period.

Table 9: Customer Usage

	Option 1		Option 2		Option 3	
Peak Period	Non-LIHEAP	LIHEAP	Non-LIHEAP	LIHEAP	Non-LIHEAP	LIHEAP
On	13.9%	14.4%	17.3%	17.7%	10.5%	10.7%
Off	66.8%	66.1%	63.4%	62.7%	70.1%	69.8%
Super-Off	19.3%	19.5%	19.3%	19.5%	19.3%	19.5%

Minnesota Power conducted a bill impact analysis (depicted in Figure 16 below) to assess whether or not a TOD rate would negatively affect low-income customers. The customers analyzed fell into four categories: standard residential, electric heating, standard LIHEAP (non-electric-heat), and LIHEAP with electric heat. For rate Option 3, the Company found no evidence that low-income customers differ in their energy usage behavior from non-low-income residential customers, and does not expect low-income customers to be disproportionately affected – positively or negatively – by a TOD rate based on rate Option 3.

The analysis for rate Option 3 showed that a standard (non-electric-heat) LIHEAP customer would have saved between $2.5 and $8 over the period from October 2017 to September 2018, an electric-heat LIHEAP customer would have saved between $16 and $28.5, a standard, non-heating, non-LIHEAP customer would pay between $0.5 and $5 more, and a non-LIHEAP electric-heat customer would save between $29 and $41 per year. When taking into the consideration the peak periods of Option 3, the usage of the LIHEAP customers during the off-peak and super-off-peak periods seems to balance out or negate their on-peak period usage, which meets the objective of the TOD rate design options.

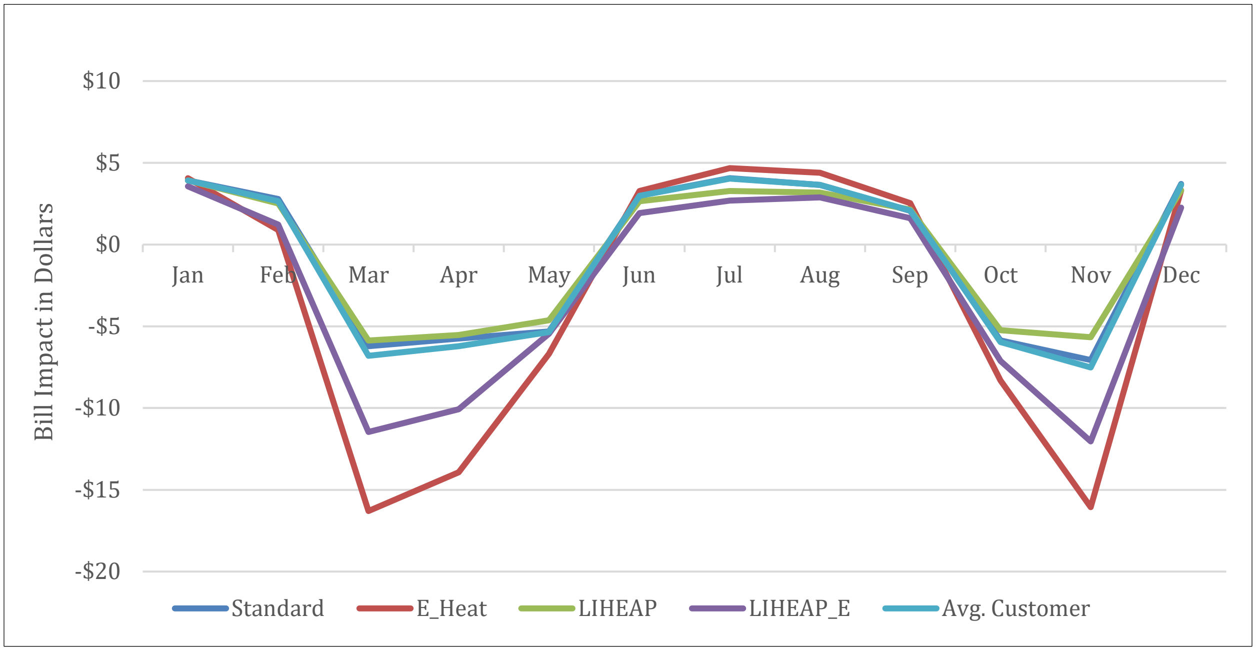

Figure 16: Bill Impacts by Customer

VI. Rate Implementation

1. FUTURE OUTLOOK – IMPLEMENTATION TIMEFRAME

Minnesota Power considers a TOD rate a compelling customer offering in the context of full-scale development. While tangible system benefits may be proven to be relatively minor in the short term, the Company believes that innovative programming such as a TOD rate can play an important role in improving grid efficiency and improve customer satisfaction through providing additional options.

The timeline for a full scale TOD rate rollout is heavily dependent on Minnesota Power's planned MDM implementation and integration (discussed in further detail on Page 6). As communicated in previous filings in the docket, with the complete deployment of AMI, Minnesota Power's AMI system will be technically capable of supporting a system-wide time varying rate offering. However, in all practicality, an MDM solution needs to be in place systemically before a system-wide rollout of this type of rate/program.

Though there was not a general consensus on a specific deployment plan, the stakeholder workgroup discussed the possibility of a phased deployment and produced the preliminary timeline provided below. (Also illustrated in Figure 17 on Page 31).

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

This is a planning and preparation period, as benefits likely will not justify the resources needed to manually fix billing errors or costs associated with manually programming each meter with TOD buckets. Specific actions could include:

- Obtain a suitable rate design, then evaluate how to deploy it
- Conduct strategic planning regarding related/ancillary programs to maximize benefit (e.g., energy conservation efforts, electric vehicles, distributed energy resources)

Phase 2: MDM implementation period (expected 2020-2021)

Phase 2 activities could include:

- Pilot the program with some customers (e.g., ~394 current pilot participants and/or EV owners) and conduct shadow billing for all other customers to identify which customers will need the most assistance with such things as managing their usage and understanding their bill. Target programs to help those customers.

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

Potential: phased roll-out of TOD Rate as AMI meters are deployed.

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

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

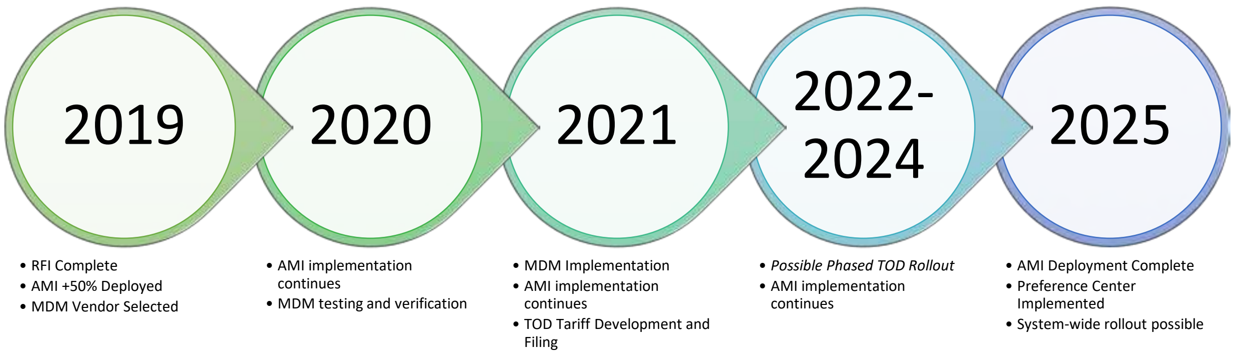

Figure 17: Phased Timeline for TOD Rollout

If the Company were to commit to a phased TOD rate rollout post MDM implementation in 2021 Phase 3), it would require targeted marketing and education outreach efforts, increased administrative resources (to support such activities as shadow billing), and a reconfiguration of the Company's AMI deployment strategy. Along with these considerations would be the uncertainty of enrollment and additional resources needed to match demand. The Company's preference is to have completed both the MDM implementation and AMI deployment prior to a full-scale TOD rate implementation. This would place a full-scale TOD rate offering in the 2024-2025 timeframe.

2. CUSTOMER EDUCATION

Customer communication and education are key components to any innovative utility program, especially when the offering is opt-out or system-wide. As evidenced through its successful implementation of the current TOD Rate Pilot, Minnesota Power is well positioned to provide a smooth and thoughtful transition for its residential customers. Minnesota Power worked closely with Commission Staff during the initial TOD Rate rollout to develop resources, communications, and tools to ensure customer communications were comprehensive and clear. Notably, Minnesota Power earned a first place award under the category of direct mail during the annual Utility Communicators International ("UCI") conference in June 2015 for its Time-of-Day materials. Numerous participant surveys associated with the current TOD rate also indicated a very high level of understanding despite the complexities of the pilot rate design. Minnesota Power intends to capitalize on its learnings from this initial experience while also leveraging the most successful aspects of the program and supplementing with innovative communications tools.

Based on its experience through the TOD Rate pilot, Minnesota Power explored a preference center solution in an effort to realize efficiencies and operational benefits while expanding engagement opportunities with customers. A preference center (aka: subscription centers) is a landing page where you tell a company what kinds of communications you want to receive from them. It's usually linked from the footer of emails—next to the unsubscribe link.[7] A preference center solution would allow customers to choose the preferred frequency and channels (e.g. text message, email, phone call) of their communications coming from Minnesota Power. They could choose which programs they are interested in learning more about and getting updates on. This would provide the utility with a queryable database to utilize in targeting customer communications. Preference solutions are common among many marketing types and customers are beginning to expect this type of communications control from any business with which they interact. Not only will this provide customers with choice, it will also allow the utility to target its programs more effectively and understand its customer needs on a more granular level.

3. COSTS OF FULL-SCALE IMPLEMENTATION

Both Minnesota Power and the Stakeholders who engaged in this process recognize the importance of a strong education and outreach strategy in creating a successful rollout of a full-scale TOD rate. As such, any costs associated with the development and implementation of an education and outreach strategy should be considered as part of the costs to implement the rate. Based on related discussions as part of the stakeholder process and internal expectations and experience, the following items were identified as education and outreach related implementation costs:

Customer Usage and Account Portal: Software enhancements for enabling customers to easily understand their usage in terms of the TOD periods and for development of a bill impact tool designed to aid customers in understanding how the new rate structure will impact their bills and make informed decisions if considering opting out of the program. Based on current vendor pricing and anticipated level of effort, the Company estimates between $50,000 and $100,000 in related implementation costs.

Education and Outreach Communication Plan and Materials: based on current staffing levels, Minnesota Power anticipates an additional resource will be needed to develop, facilitate, and implement a robust communication strategy and the related materials in order to ensure customers are well educated and prepared for implementation of the rate itself.

[7] https://www.leadmd.com/best-practices/blog/whats-a-preference-center-why-you-should-care/

Customer Support: The Company anticipates an additional customer programs and services representative will be necessary for 12 to 18 months surrounding the implementation in order to support the increased call volume and direct customer consultation expected as the rate is deployed. Minnesota Power anticipates an influx of calls related high bill impacts, general inquiries about the rate, requests to understand bill impacts of opting out, etc. Some of these calls could be handled through existing Call Center resources, but many of which would require a more detailed and intensive level of service. Additionally, if the implementation plan requires or includes shadow billing in some form, there would likely be additional implementation and resource costs to consider. The magnitude of these costs would likely depend on the approach employed.

Measurement and Evaluation:

The Company will likely need to invest in the appropriate measurement and evaluation tools and services for tracking progress and effectiveness of a full-scale TOD rate offering. Ensuring that the implemented rates are providing the intended and desired effects will require extensive evaluation and tracking of customer's usage behaviors and effects on the system. The costs related to these activities will depend on the approach employed.

4. TRACKING, REPORTING, AND MEASURING

In its August 18, 2018 Order in the docket, the Commission required Minnesota Power to submit annual informational filings providing a summary of the time-of-day pilot program, including participation rates, an update on Minnesota Power's meter communications infrastructure, and the Company's plans to offer a system-wide rollout of residential time-of-day rates. The Company will continue to report on the pilot as ordered. Additional reporting will be identified as appropriate with the implementation of a new time-of-day tariff. The updated metrics could include such items as estimated peak reduction, participation rates, customer feedback, etc. The Company will continue to share its learnings whether through its current pilot, or a future time-of-day tariff and program.

VII. Conclusion

Minnesota Power gained valuable insight through its TOD stakeholder process. The process has been a positive learning experience supported by industry expertise via Navigant consulting and facilitation by the Great Plains Institute and Center for Energy and the Environment. The lessons learned, and insight gleaned, from the Company's existing TOD Rate were advantageous and key for informing what a full scale TOD Rate may look like on Minnesota Power's system. At the same time, the Company was challenged to contemplate scenarios that may not have been considered viable in the past. The alternative rate designs communicated through this filing are an essential foundation on which the Company can build future rate offerings. Considering the Company's planned MDM implementation timeline, a full-scale TOD Rate is not advisable until the 2024 timeframe (as outlined on Pages 30-31). Keeping this in mind, the Company is motivated to take the lessons learned through its stakeholder process and continue refining the rate design options with further feedback and analysis. The Company looks forward to continuing the dialogue regarding the appropriateness and possible designs of time varying rates for its customers.

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Respectfully submitted,

Jenna Warmuth
Senior Public Policy Advisor
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3448
jwarmuth@mnpower.com