MINNESOTA PUBLIC UTILITIES COMMISSION

# Staff Briefing Papers

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| Meeting Date | August 1, 2019 | Agenda Item **2 |
| Company | Minnesota Power (MP) | |
| Docket No. | **E-015/M-18-735**<br><br>**In the Matter of Minnesota Power's Petition for Approval of an Industrial Demand Response Product** | |
| Issues | 1. Should the Commission approve one or more of Minnesota Power's (MP's) proposed Demand Response Products "A", "B", or "C"? Product A is similar to MP's current interruptible rate. Product B is a new long-term capacity product with an energy curtailment component and a 150 MW cap. Product C is a market surplus Demand Response product.<br><br>2. Should the Commission approve Cost Recovery Method "1" (a flat per-kWh cost recovery surcharge collected from all firm customers) or Method "2" (a per-kWh surcharge based on the apportionment of the final rate case revenue deficiency MP's last rate case)?<br><br>3. Should the Commission require MP to file regular compliance reports? | |



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| ✓ Relevant Documents | Date |
|---|---|
| **Minnesota Power, *Petition*** | December 7, 2018 |
| **Citizens Utility Board of Minnesota, *Comments*** | February 20, 2019 |
| **Office of the Attorney General, *Comments*** | February 20, 2019 |
| **Large Power Intervenors, *Comments*** | February 20, 2019 |
| **Fresh Energy, *Comments*** | February 20, 2019 |
| **Department of Commerce, *Comments*** | February 20, 2019 |
| **Advanced Energy Management Alliance, *Comments*** | February 20, 2019 |
| **Citizens Utility Board of Minnesota, *Reply Comments*** | March 13, 2019 |
| **Large Power Intervenors, *Reply Comments*** | March 13, 2019 |
| **Minnesota Power, *Reply Comments*** | March 13, 2019 |
| **Advanced Energy Management Alliance, *Reply Comments*** | March 13, 2019 |
| **Department of Commerce, *Response to Reply Comments*** | April 25, 2019 |
| **Minnesota Power, *Supplemental Comments*** | June 28, 2019 |
| **Large Power Intervenors, *Supplemental Reply Comments*** | July 3, 2019 |
| **Verso Corporation, *Comments*** | July 5, 2019 |

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## I. Summary of the Issues

Minnesota Power (MP) requests Commission approval of a suite of three demand response (DR) products, referred to as Product A, Product B, and Product C. Product A is similar to MP's current interruptible rate, Product B is a new long-term capacity product with an energy curtailment component and a 150 MW cap, and Product C is a market surplus product.

The Commission will need to decide whether to approve MP's petition, or whether it should approve one or more DR product(s) and deny one or more DR product(s). Parties are split over which products should be approved.

In short, MP, the Large Power Intervenors (LPI), Fresh Energy, and Advanced Energy Management Alliance (AEMA) support MP's petition, although Fresh Energy and AEMA suggest modifications.

The Citizens Utility Board of Minnesota (CUB), the Office of the Attorney General (OAG), and the Department of Commerce (Department) fall into the camp of parties who oppose the petition, although in different ways: CUB recommends denying the entire petition. The OAG recommends denying the petition as proposed, but the OAG is willing to accept certain modifications. The Department recommends approving Products A and C, but recommends denying Product B.

If the Commission approves MP's Petition, the Commission must then decide what cost recovery method to approve. MP proposes two options, "Cost Recovery Method 1," which is a flat per-kWh cost recovery surcharge collected from all firm customers, and "Cost Recovery Method 2," which is a per-kWh surcharge based on the apportionment of the revenue deficiency from MP's last rate case. MP and LPI support "Method 2," which has a higher rate impact to residential customers relative to large power customers (in percentage terms).

Finally, the Commission will need to decide whether to require MP to file regular compliance reports, and if so, how often. The Department recommends an annual compliance report (but only if Product B is approved), which would contain several items. Fresh Energy and the OAG recommend MP file quarterly reports, for similar reasons.

## II. Background

### *A. MP's System Characteristics and Existing DR Programs*

MP is a winter-peaking utility[1] with a peak demand of slightly more than 1,700 MW.[2] Its existing DR capability, which has fluctuated over time due to annual changes to both MISO

[1] MP's winter peak is typically between 30 and 40 MW higher than its summer season peak.

[2] Docket No. 17-568, *In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward *Resource Package*, Petition, at Page 2-9.

capacity accreditation and large power electric service agreements (ESAs), currently amounts to about 260 MW, as shown by the table below:[3]

| Planning Year | Accredited Demand Response (UCAP-MW) |
|---|---|
| 2018-2019 | 263.1 |
| 2017-2018 | 265.4 |
| 2016-2017 | 208.0 |
| 2015-2016 | 107.6 |
| 2014-2015 | 107.0 |
| 2013-2014 | 105.9 |
| 2012-2013 | 131.8 |
| 2011-2012 | 131.8 |
| 2010-2011 | 161.3 |
| 2009-2010 | 88.6 |

MP's 260 MW of accredited DR is "emergency DR" and is accredited annually as a capacity resource in the MISO Resource Adequacy Program, valued based on its availability at the MISO system peak.[4] Notably, the 260 MW of DR equates to approximately 15% of MP's peak demand, which is high relative to other Minnesota utilities. (Xcel Energy's DR capability, for example, is about 11% of DR capability as a percentage of peak demand.)

As MP explained, this type of DR is contracted through one-year load-shedding agreements with its large power customers, which have been in place since the early 1990s, and curtailments are driven by MISO system emergencies:

> Minnesota Power has had interruptible agreements in place with large industrial customers and has been utilizing this resource in response to system emergencies since 1993. The system used to curtail customer load is automated. When Minnesota Power receives a directive from MISO, the Company executes a customer communication plan and operators are able to interrupt all or a percentage of available (operating) interruptible load by sending an interrupt signal to participating industrial customers. These customers have equipment installed and programming in place that enables the required amount of load to be shed automatically.[5]

[3] "UCAP," or unforced capacity, is the MW value of a capacity resource in the MISO Resource Adequacy Program. For supply-side resources, the UCAP value is equal to the installed capacity of the unit multiplied by the forced outage rate.

[4] MP began to participate in the MISO Resource Adequacy Program in the 2009-2010 MISO Planning Year, which is why the table begins with that year.

[5] MP reply comments, at 9.

Of course, MP's interruptible agreements with its large industrial customers are not reflective of MP's entire suite of demand-side management (DSM) programs, which includes energy savings measures as well as some residential and commercial heating DR. However, the amount of *MISO-accredited* DR capability from MP's residential and commercial classes is minimal—almost all of MP's accredited DR is through large power service interruptible riders. Below is a list of MP's interruptible DR resources/programs available on its system and their total curtailable potential (in MW) in the summer and winter seasons:[6]

- *Residential and Commercial/Industrial Dual Fuel Interruptible Electric Service:* This program deals almost exclusively with electric heat, so there is minimal load to interrupt in summer months (just 4 MW, mostly from commercial/industrial loads). The available curtailable load in winter months depends on temperature and heating loads, mostly of residential customers. MP estimates that approximately 30 MW of interruptible load is available during a typical winter peak.

- *Rider for Released Energy:* There are currently no customers providing capacity or receiving credits.

- *Rider for Voluntary Energy Buyback:* There are current no customers providing capacity or receiving credits.

- *Rider for Large Power Incremental Production Service:* Energy that is available for interruptions will often be zero MW when loads are low or moderate and may be up to 10 to 15 MW in both summer/winter when MP's total system loads are very high.[7]

- *Replacement Interruptible Service:* This is MP main DR rider for large customers. Over the past five MISO Planning Years, the capacity available ranged from approximately 100 MW up to 260 MW.

- *Time of Day with Critical Peak Pricing Pilot:* A residential-only pilot program, in which the roughly 400 participants pay more for usage during on-peak hours and Critical Peak Pricing (CPP) events and receive a discount for usage during off-peak hours. The program does not allow MP to interrupt load; however, during a CPP period, the CPP signal encourages load reduction.

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[6] MP response to PUC Information Request No. 1.

[7] In MP's 2016 rate case, the Commission rejected MP's proposed changes to its Incremental Production Service, finding that "the Company's proposal assume cost savings but does not include cost data to support that claim. As a result, it [was] unclear to what extent any savings could be achieved. Further, the Commission is not persuaded that the combination of additional energy curtailment, along with increased consumption, achieve the goal of the LP-IPS Rider or Minnesota's energy policy goals concerning conservation and renewable energy." Order, Docket No. E-015/GR-16-664, pp. 87-90 (March 12, 2018).

MP's load factor[8] is roughly 80%,[9] which, as MP stated in its Petition, reflects "one of the highest concentrations of industrial load in the country."[10] In fact, nine of MP's large customers currently comprise 61% of its energy sales.

Again, while MP has a relatively high amount of curtailable load (in terms of DR as a percentage of peak demand), these are one-year DR agreements that can be called upon (but often aren't) during a MISO emergency event. MP believes there is substantial value in long-term agreements with its large industrial customers for "flexible, firm, and curtailable"[11] DR, which MP can utilize for its *own* system for economic reasons, not just MISO system emergencies.

MP's Petition requests that the Commission approve a suite of three DR products that the Company believes maximizes this value. Each type of DR that MP proposes, which MP refers to as Product A, Product B, and Product C, has a different purpose and aims to achieve different benefits for its system.

As defined in the revised Rate Book, included as Appendix D of the Petition, the three products are:

- Demand Response Product A - Short-Term Emergency Capacity;
- Demand Response Product B - Long-Term Emergency Capacity Curtailable with Firm Load Control periods; and
- Demand Response Product C - Market Surplus Service.

Broadly speaking, these briefing papers are structured to provide: (1) an overview of the three DR products; (2) a summary of the parties' comments on MP's Petition; and (3) staff's discussion of each DR product, including a guide to the Commission decision options. First, staff will discuss the procedural background for the DR products to contextualize MP's Petition.

### *B. Procedural Background*

The Commission has addressed and provided directives for new DR resources on MP's system in several recent dockets, primarily three: MP's 2016 rate case, its 2015 Integrated Resource Plan (IRP), and the Nemadji Trail Energy Center (NTEC) proceeding. Below, staff will briefly summarize how each proceeding addressed new DR for MP's system.

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[8] A utility load factor refers to the utilization rate of its electric system. The load factor percentage is derived by dividing total energy consumed over a period of time by the product of the maximum demand and the number of hours in the time period—a high load factor indicates a relatively energy-intensive system.

[9] Docket No. 17-568, *In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward *Resource Package*, Petition, at Page 1-2.

[10] Petition, at 3.

[11] Petition, at 3.

- *2016 Rate Case (Docket No. 16-664)*: In MP's most recent rate case,[12] the Company did not propose changes to its Large Power Interruptible Service Rider; however, LPI argued that interruptible load was an important component of resource planning, and interruptible rates are one of the incentives used to induce DR among customers. LPI introduced its own DR Rider proposal (patterned after the Northern Indiana Public Service Company Rider 775) as a basis for making changes to MP's DR rider.

  The Administrative Law Judge (ALJ) concluded that because MP did not propose a change to its Large Power Interruptible Product, there was no basis to further consider LPI's proposal. However, MP and LPI were "encouraged to discuss the issue and address it with the PUC in the appropriate forum."

  LPI asked that the DR Rider it sponsored be adopted by the Commission or, alternatively, that the Commission order MP to work with LPI and other stakeholders to develop a DR Rider and submit a petition for approval within six months of the final order.

  MP opposed LPI's DR proposal, stating that further development of costs and related issues is needed to better understand the implications of the proposal and how to effectively implement DR. The Department commented that the "addition of this resource product [DR Rider] needs to be balanced with the overall needs of Minnesota Power customers." The OAG questioned LPI's assumptions in estimating the value of interruptible capacity.

  In the end, the Commission's March 12, 2018 Order recognized that DR programs deserves further discussion to provide parties an opportunity "to develop the relevant issues and reach consensus."[13] Thus, the Commission required MP to work with LPI and other stakeholders to develop a DR Rider based on stakeholder input. The Commission instructed MP to "file the Rider within six months of the date of this order."[14]

- *Nemadji Trail Energy Center, or "NTEC" (Docket No. 17-568)*: In the NTEC proceeding, the Commission approved three affiliated interest (AI) agreements for MP's purchase of a 50% share of the 525 MW NTEC combined cycle gas plant. In addition, the Commission adopted the ALJ Report, which concluded that DR was outside the scope of the NTEC proceeding and should be addressed in a new miscellaneous docket.[15] According to the Commission's January 24, 2019 NTEC Order:

  > 5. Minnesota Power shall continue to develop, based on stakeholder input, a demand response rider and corresponding methodology for cost recovery

[12] Docket No. 16-664

[13] Commission Order, Docket No. E015/GR-16-664, March 12, 2018, at 85-86.

[14] Commission Order, Docket No. E015/GR-16-664, March 12, 2018, at 85-86.

[15] ALJ Report, Finding of Fact 514.

and shall file the rider in a new miscellaneous docket within six months of the date of the final written order in Docket No. E-015/GR-16-664.

- *2015 IRP (Docket No. 15-690)*: MP's 2015 IRP also addressed DR resources, although with far less specificity than the rate case and NTEC dockets, in that it did not evaluate new DR products/proposals. The Commission's IRP Order, issued on July 18, 2016, required MP to initiate a competitive-bidding process for DR resources (in addition to bidding processes for solar and wind). The DR bidding process was to some extent conceptual and experimental in nature, but its purpose was to allow DR resources to be considered as one of "a wide variety of replacement options" to be examined in MP's next IRP, upon the Company's retirement of the coal-fired Boswell 1 and 2 units.

  As the Commission may recall, MP's next IRP has been delayed due to the NTEC proceeding. This was because MP filed a petition for approval of its wind/solar/gas Energy*Forward* Resource Package on July 28, 2017, and the Commission's September 19, 2017 Order referred the evaluation of the AI agreements for NTEC to the Office of Administrative Hearings for contested case proceedings. Since the NTEC proceeding would have likely created overlap with the next IRP, the Commission delayed the next IRP filing by one year. (One outcome of the NTEC case was another one-year delay to the next IRP, which is now due in October 2020.)

The Commission's previous orders, which directed the Company to pursue a new DR product in collaboration with stakeholders, are relevant to a fundamental aspect of the instant case—the need for a new DR resource. To briefly summarize, the Department, OAG, and CUB argued the need for new DR has not been demonstrated, and all three parties recommend the Commission should at least deny Product B (the Department supports Products A and C). MP and LPI responded that the question of need is not before the Commission; rather, the need was recognized when the Commission ordered this filing, so in their view the Department's, OAG's, and CUB's assertions are misguided.

### *C. Stakeholder Engagement*

MP characterized the development of the proposed DR products as an extensive, collaborative process, noting, "Prior to and since the Rate Case Order, Minnesota Power has been working with industrial customers to develop a new DR product and associated cost recovery methods that meet the needs of participating customers while also ensuring the product provides benefits to all the Company's customers."[16] LPI echoed these remarks, noting in its reply comments that "the discussion about enhancing the Company's industrial DR product offerings has been ongoing for several years."[17]

Moreover, according to MP, some of the product design elements incorporated into the Petition emerged as "the result of collaboration with the customers who will provide the

[16] Petition, at 12.

[17] LPI reply comments, at 6.

resource, as well as the thoughtful input provided by interested stakeholders representing clean energy groups, consumer advocates, and more."[18]

The Petition discussed a few takeaways of the workgroup's interests; MP stated, for example:

> Some key themes the Company heard from the stakeholders present include: a need for participating customers to have flexibility in the program, clear and easy to follow program guidelines, options for customer cost savings, the ability to treat DR like a system resource, and recognition of the system and environmental benefits that DR can provide.[19]

For further information, Appendix A of the Petition includes presentations and discussion notes from two stakeholder meetings, one from September 25, 2018 and another from November 20, 2018, both held in Duluth.

## III. MP Petition

### *A. Summary of Products A, B, and C*

Product A is basically MP's current interruptible rate, which entail one-year agreements for curtailable load during emergency events. Product B is a new long-term capacity product with emergency and energy curtailment components, which is proposed to have a 150 MW cap. Product C is a market surplus DR product.

The following table provides the essential features of the three proposed DR products:

[18] Petition, at 3.

[19] Petition, at 14.

| DR Product | Main Features | Addt'l. Comments |
|---|---|---|
| Product A<br>(Short-Term Emergency Capacity Product) | Emergency-only capacity product<br><br>Credit of \$0.60/kW of interruptible billing demand per month, to be updated annually<br><br>No more than:<br>- 5 events per year<br>- 4 hours per event<br><br>No less than 2 hours advance notice | One-year agreements<br><br>Similar to existing interruptible rate |
| Product B<br>(Long-Term Emergency Capacity Curtailable with Firm Load Control Periods Product) | Uses the same design for emergency capacity events as Product A<br><br>\$7,000 per MW-month[20] capacity credit for up to 150 MW of capacity<br><br>MP can curtail up to 90,000 MWh annually at a \$30/MWh credit to the customer<br><br>Customer has the option to (a) receive the \$30/MWh credit or (b) "buy through" and pay a "market-like rate"<br><br>Max of 600 hours firm load control annually | 10-year agreement<br><br>Allows MP to call for economic interruptions ("Firm Load Control")<br><br>Cap of 150 MW |
| Product C<br>(Market Surplus Service Capacity Product) | Emergency-only capacity product used for excess capacity<br><br>MP will "facilitate options" for a customer's excess demand response capacity that doesn't fit into Product A or B<br><br>Contract periods of 3 or 5 years are available | Intended for customers seeking a capacity product with more than a 1 year commitment but less than 10 years |

There are a number of technical, esoteric terms used throughout the Petition. The DEFINITIONS section of the Rider for Large power Demand Response Service (Appendix D) includes a list some of the terms used frequently in the Petition:

> **Demand Response Billing Demand**: Capacity volume associated with the Rider for Large Power Demand Response Products A, B and C that will receive Demand Charge Credits on a monthly basis, as specified herein.
>
> **Demand Response Contract Demand**: The aggregate of Customer's accredited capacity of Products A, B and C under this Rider.

[20] A MW-month or kW-month is how much capacity on a megawatt (MW) or kilowatt (kW) measurement that is available during a one month time period.

> **Firm Load Control Period**: Period in which participating Customers can either physically reduce their energy or buy-through at the Company's incremental energy cost plus an adder, as specified herein.
>
> **Firm Service Level**: Customer's targeted demand reduction threshold that is specified when customer registers for Products A, B and C.
>
> **Emergency Curtailment**: Requirement for participating Customers to physically reduce load to their Firm Service Level.

Note that all of the proposed DR products have an emergency curtailment component, the conditions of which must be in accordance with the MISO Module E-1 of the Business Practices Manual for Resource Adequacy.

Also, as the previous table shows, Products A and B have the same emergency capacity events:

- Maximum number of annual emergency events: 5 events
- Maximum duration of emergency events: 4 hours
- Minimum notice of emergency events: 2 hours

According to MP, the emergency curtailment product "is intended to utilize emergency capacity only if required by MISO or if system integrity is threatened."[21] Of note, in a January 14, 2019 response to DOC Information Request No. 1, MP explained that neither MISO nor MP has called on the Company's DR customers in the past five years.[22] However, in a February 18, 2019 response to LPI Information Request No. 1, MP noted that, due to extreme temperatures experienced during the week of January 27, 2019 (the polar vortex event), MP had approximately 200 MW of industrial DR load offline.[23] This is relevant because some argue the monthly compensation aspect of Product B is unreasonably high because DR is not being used; LPI noted the polar vortex event as evidence that the DR is not merely theoretical.

In addition to the emergency capacity events that are part of Products A, B, and C, a unique element that distinguishes Product B is the provision of a second circumstance in which load can be curtailed, Firm Load Control periods. Firm Load Control periods are curtailment events that can be called by MP for economic reasons – when, for instance, the cost of obtaining or generating electricity is higher than the price paid for curtailment. These are energy-related curtailment events driven by MP's hourly incremental energy costs. During a Firm Load Control period, customers may consider the economics of whether to be curtailed or to "buy through" (i.e. non-curtailment), which staff will discuss further in the next section. The following conditions will apply for Firm Load Control periods:

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[21] Petition, at 16.

[22] OAG comments, Exhibit 5, Page 2 of 3 (February 20, 2019).

[23] LPI comments, *See* page 10 and Attachment A – Information Request No. 1.

- Maximum number of annual (calendar year) Firm Load Control hours: 600 hours
- Maximum of 2 Firm Load Control periods per day
- Maximum of 12 hours of Firm Load Control periods per day
- Maximum Firm Load Control duration per occurrence: 12 hours
- Minimum Firm Load Control duration per occurrence: 4 hours
- No more than four Firm Load Control periods in any seven days of the week (Sunday-
- Saturday)
- Notice will be given either the day-ahead or real-time with four hours advance notice through an e-mail notice.

As a point of clarification, when MP references 150 MW of new demand response, as well as its association to the IRP and NTEC proceedings, MP is referring specifically to the 150 MW cap for the proposed Product B. On pages 10-11 of MP's Petition, for instance, the Company stated:

> [A] 150 MW DR product, representative of what is being proposed here as Product B, was included in the base case of the Strategist analysis in the NTEC proceeding.

MP also noted that the 150 MW cap is reflective of its resource planning analysis:

> Providing an initial cap at 150 MW reflects how industrial DR resources were modeled in previous resource plans and recent resource acquisitions petitions.[24]

Moreover, when MP refers to avoided energy benefits, again, the Company is referring exclusively to Product B. This is because only Product B includes the Firm Load Control periods for curtailed energy. Customers who interrupt operations will be compensated with a $30 per MWh Physical Interruption Energy Credit. (Note that the Physical Interruptible Energy Credit will only be paid to customers during a Firm Load Control Period, and not for an emergency event.)

Finally, all of the new DR product options for MP's largest industrial customers will be implemented in new or amended Electric Service Agreements (ESAs). ESAs are subject to the Commission's approval under Minn. Stat. § 216B.05, which provides for customer-specific rates.

The next section will provide a more detailed discussion of each proposed DR product.

1. Product A

MP stated on page 16 of its Petition:

> Product A is very similar to the interruptible product Minnesota Power currently offers to its large industrial customers. The credit for Product A during the initial year is currently anticipated to be approximately $0.60 per kW of interruptible billing demand per month, and it is contemplated that the amount of the credit

[24] Petition, at 10-11.

may be updated annually based on the current market price trends for short term capacity.[25]

The current product offering that MP is referring to is the Replacement Interruptible Service program, which is offered to customers on an annual basis and governed by the Rider for Released Energy. MP has offered Replacement Interruptible Service for over 15 years. The table below compares Product A to the current Replacement Interruptible Service program:

| Product Characteristics | Product A | Replacement Interruptible Service |
|---|---|---|
| Product Term | 1-year annual contract | 1-year annual contract |
| Product Type | MISO Emergency Only | MISO Emergency Only |
| Annual Credit | Represent market conditions | Currently $0.60/kW-month/reviewed annualy |
| Maximum Number of Annual Curtailments: | 5 | 5 |
| Maximum Duration of Curtailments: | 4 Hours | 4 Hours |
| Minimum Notice of Curtailable Service Curtailments: | 2 Hours | 2 Hours |
| Accredit Capacity with MISO | Yes | Yes |

As shown above, the Replacement Interruptible Service rider has a demand credit of $0.60 per kW-month, which is the same demand credit MP uses to estimate program costs for Product A. The $0.60 per kW-month is informed by: 1) the minimum price participating customers need to be compensated for the risk of lost production during an emergency curtailment event, and 2) capacity value for short term capacity prices in MISO Local Resource Zone 1.

Below is a table with 5-years of historical clearing price data from MISO's Planning Resource Auction, as well as the average for that period. Of note, the $0.60 per kW-month clearing priced (based on the 2016-17 MISO Planning Year) was the highest clearing price over the last five years:[26]

| | Clearing Price from MISO Planning Resource Auction (Local Resource Zone 1) | |
|---|---|---|
| | $/MW-Day | $/ kW-Month |
| PY 14-15 | $3.29 | $0.10 |
| PY 15-16 | $3.48 | $0.11 |
| PY 16-17 | $19.72 | $0.60 |
| PY 17-18 | $1.50 | $0.05 |
| PY 18-19 | $1.00 | $0.03 |
| Average | $5.80 | $0.18 |

As shown in the next table, a $0.60 per kW-month demand credit yields an annual product cost in the $360,000-$1.44 million range, depending on the subscription level:

[25] Petition, at 16.

[26] The jump in clearing prices for the MISO Planning Resource Auction is likely attributable to the fact that the 2016-17 Planning Year coincides with the implementation of the EPA Air Toxics Rule. Around 13 MW of coal in the MISO footprint was retired to comply with the Air Toxics Rule.

**PRODUCT A**

| kW (A) | Demand Credit kW-mo. (B) | Estimated Cost (A*B*12 months) |
|---|---|---|
| **0** | $0.60 | $0 |
| **50,000** | $0.60 | $360,000 |
| **100,000** | $0.60 | $720,000 |
| **150,000** | $0.60 | $1,080,000 |
| **200,000** | $0.60 | $1,440,000 |

Staff notes these are annual program costs, not incremental rate impacts. Unlike Product B, which is an entirely new offering, costs associated with Product A are already accounted for because they were approved in MP's 2016 rate case (see MP's explanation on page 24 of the Petition).

2a. Product B: Two Different Cost Aspects

In response to OAG Information Request No. 29, MP explained how the economic interruption (Firm Load Control) process would work for Product B, as well as the conditions that will trigger economic curtailments:

> The procedure for MP having an economic interruption will include comparing MP's forecasted incremental cost, including applicable real-time locational marginal prices for the Company's load zone, to the Physical Interruptible Energy Credit. If the estimated cost is expected to be higher for a four-hour period of time or longer, it could trigger an economic interruption or Firm Load Control Period, depending on whether Product B is the most economical resource for Minnesota Power customers at the time, and assuming that the other Firm Load Control period requirements are met (such as per day or per year limitations).[27]

Thus, Product B has two different cost aspects: the costs which correspond to the demand credit and the energy credit for economic interruptions. Product B's demand credit is $7,000 per MW-month (or $7 per kW-month). MP's cost estimate is based on the assumption of maximum participation by the large industrial customers–that is, it is assumed that the large industrial customers have disposed the entire 150 MW of capacity for curtailment/interruption.

In response to OAG Information Request No. 11, MP provided the following tables of the estimated demand and energy costs. (Staff formatted these tables for readability, but did not change any of the information.) At a credit of $7/kW for 12 months and the entire 150 MW of subscribed capacity, the total cost works out to $12.6 million/year:

[27] OAG comments, Exhibit 9, MP Response to OAG Information Request No. 29.

**PRODUCT B – DEMAND COST**

| kW (A) | Demand Credit kW-mo. (B) | Estimated Cost (A*B*12 months) |
|---|---|---|
| **150,000** | $7.00 | $12,600,000 |

Applying the jurisdictional factor of 84.360%, the Minnesota-portion of cost works out to:

$12.6 million/year x 0.84360 = $10.6 million/year.

Product B also entails a $30 per MWh Physical Interruption Energy Credit for customers who interrupt operations for economic purposes, which MP proposes to recover through the Rider for Fuel and Purchased Energy Adjustment. This credit is applied when customers physically interrupt load for non-emergency reasons.

Assuming that customers interrupt load of 150 MW for 50% of the maximum 600 hours, MP would issue credits of about $1 million per year:[28]

**PRODUCT B – ENERGY COST**

| kWh | @ 75% load factor energy (A) | Physical Interruptible Credit / kWh (B) | Est. Cost (A*B*300 hours) |
|---|---|---|---|
| **150,000** | 112,500 | $0.03 | $1,012,500 |

If customers are interrupted but choose to buy through, then MP would concurrently collect some offsetting revenues for the added cost it incurs in the fuel clause.

2.b. Product B: Buy-Through Provision

Product B also offers the ability for participants to “buy through” the event—in other words, not shed load—at the incremental cost, plus an adder. MP noted that its large customers wanted to retain some flexibility when making a long-term commitment for a portion of their load to be curtailable:

> Through many customer and stakeholder meetings, these large industrial stakeholders stated their need for a buy through provision to ensure flexibility in their operations and the opportunity to make economic decisions that are required to compete in a global marketplace.[29]

If the customer elects to buy through, the energy charge will be based on the Company’s hourly incremental energy costs during the time of the sale, including MISO market operator costs incurred by the Company, plus a $5.00/MWh adder. The incremental energy cost is determined

[28] See OAG Comments, Exhibit 1 (MP’s response to OAG Information Request No. 11).
[29] MP reply comments, at 2-3.

each hour of the month during which energy is taken and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the energy.

Appendix C of the Petition, an excerpt of which is shown below, provides an illustrative example of how a hypothetical, 100 MW customer could decide to shed load or buy through the curtailment period. This customer's Firm Service Level is 50 MW, which means this customer has agreed to make half of its load curtailable during the Firm Load Control period. The red-shaded area in the upper left is the alert, and the yellow-shaded area shows the five-hour Firm Load Control period that was called. This particular customer ultimately shed 45 MW of load and chose to buy through 5 MW (which is priced at MP's incremental energy cost plus a $5/MWh adder):

| Hour Ending | Firm Load (MW) | Firm Service Level (MW) | Firm Load Control (MW) | Buy-through (MW) |
|---|---|---|---|---|
| | A | B | AVG(RED Cells) - A | MAX (A - B, 0) |
| 100 | 100 | 50 | | |
| 200 | 100 | 50 | | |
| 300 | 100 | 50 | | |
| 400 | 100 | 50 | | |
| 500 | 90 | 50 | | |
| 600 | 90 | 50 | | |
| 700 | 90 | 50 | | |
| 800 | 90 | 50 | | |
| 900 | 55 | 50 | 45 | 5 |
| 1000 | 55 | 50 | 45 | 5 |
| 1100 | 55 | 50 | 45 | 5 |
| 1200 | 55 | 50 | 45 | 5 |
| 1300 | 55 | 50 | 45 | 5 |
| 1400 | 100 | 50 | | |
| 1500 | 100 | 50 | | |
| 1600 | 100 | 50 | | |
| 1700 | 100 | 50 | | |
| 1800 | 100 | 50 | | |
| 1900 | 100 | 50 | | |
| 2000 | 100 | 50 | | |
| 2100 | 100 | 50 | | |
| 2200 | 100 | 50 | | |
| 2300 | 100 | 50 | | |
| 2400 | 100 | 50 | | |

In this example, the hypothetical customer:

1. has 100 MW of Firm Load;
2. has a Firm Service Level of 50 MW; and
3. decreased their Firm Load to 55 MW during the event (i.e. had 45 MW of Firm Load Control).

Although the customer had committed to reduce load to 50 MW (Firm Service Level), because of its decision to buy through, the customer's load was brought down to only 55 MW during the event.

The Physical Interruption Energy Credit is specific to the Firm Load Control period (the yellow-shaded area). The Physical Interruptible Energy Credit is $30/MWh, and there was 45 MW of Firm Load Control over a 5-hour Firm Load Control period. Thus, the amount paid to the customer, which will be recovered through the Rider for Fuel and Purchased Energy Adjustment, would be $30/MWh x 45 MW x 5 hours = $6,750.[30]

In total, the applicable credits and charges are as follows:

- Demand Credit = 50 MW x $7,000 x 1 month = $350,000/month (credited whether there is interruption or not);

- Energy Credit = 45 MW x 5 hours x $30/MWh = $6,750 (credited only when an economic curtailment is called); and

- Buy-Through Cost = (5 MW x hourly marginal cost) + (5 MW x 5 hrs. x $5/MWh adder).

Staff notes that the demand credit remains the same regardless of how customers might choose to buy through an event. This is probably because the 10-year ESA is a contract to compensate large industrials customers, at the $7,000/MW-month proposed demand credit, based on the Firm Service Level agreed to when the customer registers for Product B. The Firm Load Control periods that customers can choose to buy through (or not) can be in different amounts of capacity and occur several times a year (and even two times a day). Therefore, in this hypothetical example, the industrial customer will be compensated a demand credit based on the 50 MW Firm Service Level even though the energy credit was based on 45 MW.

3. Product C

MP describes Product C as an emergency-only capacity product that can be used for excess capacity that doesn't fit into other DR products or MP's needs for MISO's resource adequacy obligations. (However, staff does not believe the language in the proposed rider indicates it is an emergency-only product.)

Product C could be used by customers who might be looking for a capacity product greater than the one-year term in Product A, but are unwilling or unable to enter into a ten-year electric service agreement (ESA). According to the proposed Rider:

> Contract periods of three or five-year are available, provided that Customer's Electric Service Agreement duration at time of bidding is at least as long as the Market Surplus Service contract, and provided that neither the Customer nor the Company has served an Electric Service Agreement cancelation notice. The Company will facilitate identification of options for a customer's excess demand

[30] MP response to PUC Information Request No. 8.e. (June 27, 2019).

> response capacity that doesn't fit into Large Power Demand Response Product A or B.[31]

Under Product C, a per kW-month demand discount, based upon the accepted offer, would be passed through to the customer providing the capacity on their monthly electric bill. In a situation where the non-participating customers are impacted by Product C, MP noted it will seek additional Commission approval to pass any cost or benefits through to customers.

Notably, MP has not estimated any costs or proposed any rates for Product C.

### *B. Rate Impacts of Product B*

This section will discuss the rate impacts of Product B only. This is because, according to MP, the costs for Product A have already been accounted for because this option is similar to MP's current DR product which was approved most recently in the rate case. As for Product C, as noted above, MP did not provide any rates or costs for Product C.

MP's proposed tariff notes that "[f]or each month that Long-Term Emergency Capacity Curtailable with Firm Load Control Periods is provided, the Customer shall receive a billing credit of $7.00 per kW-month."[32] The demand credit will be applied to the subscribed capacity per month whether there is any curtailment or not.

MP has presented two different cost recovery methods, which would have basically the opposite impact on residential customers. The following figure is from the OAG's initial comments:

**Chart 1**
**Bill Impacts for MP's Cost Recovery Proposals**

| | Option 1 | Option 2 |
|---|---|---|
| Residential | 1.30% | 2.10% |
| Large Power | 2.00% | 1.20% |

MP estimated that at the 150 MW cap for Product B, with a residential customer rate impact of about 1.3-2.1%, customers would incur a $1.01-$1.59 monthly bill impact:

> The rate impact [of Product B] to a typical Residential customer's monthly bill would be a maximum increase of $1.01, or 1.3%, under Method 1, and $1.59, or 2.1%, under Method 2, based on monthly usage of 750 kWh.[33]

In response to PUC Information Request No. 5, MP provided a step-by-step calculation of residential customer bill impacts under 10 MW, 50 MW, 100 MW, and 150 MW subscription

[31] Appendix D, Electric Rate Book, Section V, Page Nos. xx.2 and xx.3.

[32] Appendix D, Electric Rate Book, Section V, Page xx.3.

[33] Petition, at 27.

scenarios. The figure below is MP's residential customer bill impact calculation under Product B's 150 MW (full subscription) scenario:

Demand Response Cost Recovery Alternatives Under Varying Subscription Levels

**150 MW**

| Cost Recovery Method 1 - 150 MW Subscribed | | | |
|---|---|---|---|
| Recovery target | $ | 12.6 | million |
| Retail Recovery target (84.360%) | $ | 10.6 | million |
| | | | |
| Test Year Usage (Firm) | | 8,864,975 | MWh |
| minus LP DR energy (75% LF) | | (985,500) | MWh |
| DR Billing units | | 7,879,475 | MWh |
| | | | |
| Flat usage charge for all customers | $ | 0.001349 | per kWh |
| | | | |
| Average Monthly Residential Impact (750 kWh) | $ | 1.01 | |

| Cost Recovery Method 2 - 150 MW Subscribed | | | |
|---|---|---|---|
| Recovery target | $ | 12.6 | million |
| Retail Recovery target (84.360%) | $ | 10.6 | million |
| | | | |
| Large Power (34.182% of Retail) | $ | 3.6 | million |
| Other Customers (65.818% of Retail) | $ | 7.0 | million |
| | | | |
| LP Firm Energy | | 5,574,721 | MWh |
| minus LP DR energy (75% LF) | | (985,500) | MWh |
| | | 4,589,221 | MWh |
| LP Rate | | 0.000792 | per kWh |
| | | | |
| All Other Energy | | 3,290,254 | MWh |
| All Other Customers Rate | $ | 0.002126 | per kWh |
| | | | |
| Average Monthly Residential Impact (750 kWh) | $ | 1.59 | |

As shown above, under Cost Recovery Method 1, there is a "flat usage charge," which is derived by dividing the $10.6 million Retail Recovery Target by the DR billing units (i.e. energy units). The resulting rate is then multiplied by 750 kWh of energy consumption per month to estimate the typical residential customer's average bill impact.

Under Cost Recovery Method 2, however, as the table above shows, the $10.6 million Retail Recovery Target is separated into "Large Power" and "Other Customers," which is $3.6 million and $7 million respectively. As with Method 1, the "Other Customers" rate in Method 2 is still calculated by dividing the Retail Recovery Target by the billing units; however, the "Other Customers" rate divides $7 million (instead of $10.6 million) by 3,290 GWh (instead of 7,879 GWh), which yields a higher charge to residential customers under Cost Recovery Method 2.

The discussion above is intended to show that MP's Method 2 has a higher bill impact to residential customers and lower bill impact to large power customers relative to Method 1. Staff will discuss the two cost recovery methods in more detail in the next section of the briefing papers.

### *C. Cost Recovery Options 1 and 2*

**Option 1**

As noted above, Cost Recovery Method 1 has a flat per-kWh recovery from all firm customers. The estimated total capacity credit (the $10.6 million at 150 MW participation) is spread over MP's most recent rate case test-year sales figure of 8,864,975 MWh, less the amount of energy associated with Product B.

The amount of annual energy associated with Product B, assuming a 75% load factor, 150 MW of maximum subscribed capacity, and 8,760 hours in a year, is calculated to be:

150 MW * 0.75 * 8,760 hours = 985,500 MWh.

The Demand Response billing denominator then works out to be:

| | |
|---|---|
| Test-Year Sales MWh = | 8,864,975 MWh |
| Less Large Power Users DR energy adjustment = | - 985,500 MWh |
| Demand Response billing denominator = | 7,879,475 MWh. |

The per-kWh charge on Firm Energy (All Customers) is then \$10.6 million/ 7,879,475 MWh = \$0.001349/kWh[34] (maximum).

This estimated rate is the upper limit of the rate that would be charged to all customers to recover the cost of demand credit.

MP notes that the 985,500 MWh attributable to the large power customers' participation in Product B is excluded from the total energy used to allocate costs as the interrupted energy is charged and credited through different means.

__Option 2__

In Cost Recovery Method 2, MP has allocated the \$10.6 million cost according to the Commission's apportionment of the final rate case revenue deficiency by customer class.

In MP's 16-664 rate case, the Commission apportioned \$4,094,217 of the \$11,977,640 revenue deficiency – 34.18% – to the Large Power rate class.

Under this method, MP is proposing to allocate 34.18% of \$10.6 million to this class, and the rest of the cost to all other rate classes as one flat rate. Here again, in the calculation of the rate additive to the Large Power Class, MP has excluded the interruptible portion of -985,500 MWh attributable to the Product B annual usage.

The details of the Cost Recovery Method 2 are presented in the table below:

| | Large Power | All Other Customers |
|---|---|---|
| **Allocation (as a % of Retail)** | 34.182% | 65.818% |
| **Target Recovery (max)** | \$3.6 million | \$7.0 million |
| **Test Year Firm Energy** | 5,574,721 MWh | 3,290,254 MWh |
| **Minus Large Power DR Energy** | -985,500 MWh | 0 |
| **Total Billing Units** | 4,589,221 MWh | 3,290,254 MWh |
| **Rate** | \$0.000792/kWh | \$0.002126/kWh |

[34] \$10,600,000/7,879,475,000KWh = \$0.00134/KWh.

As discussed in the previous section, MP estimated that the rate impact on a typical residential customer's monthly bill would be a maximum increase of $1.01, or 1.3%, under Method 1, and $1.59, or 2.1%, under Method 2, based on monthly usage of 750 kWh.

For Large Power customers, MP has estimated the rate impact to be 2% increase under Method 1 and 1.2% increase under Method 2. (A Large Power customer's' typical monthly bill is $3,768,305.) This rate impact does not account for the reduction in the energy cost during the Firm Load Control periods or the possible avoided cost of offset or deferred capacity over the 10-year period.

MP maintains that, in addition to being consistent with apportionment of the final rate increase in MP's last rate case, Cost Recovery Method 2 also allocates more cost to the customer classes that benefit from peaking capacity products like DR. High load factor customers like the Large Power class, utilize more energy relative to the required capacity, whereas lower load factor customers like residential and commercial customer classes require higher ratios of capacity relative to energy consumed to reliably serve their needs.

**Recovery of Energy Credit**

Customers subscribing to Product B will not receive any energy credits unless and until MP calls an economic interruption. (As staff noted earlier, there is no energy credit for the emergency curtailment component.)

MP seeks approval to modify its existing Rider for Fuel and Purchased Energy to include in the Average Fuel and Purchased Energy Cost section the recovery of the cost of the Physical Interruptible Energy Credit of $30 per MWh paid to customers for avoided energy purchases under the Rider for Large Power Demand Response Service.

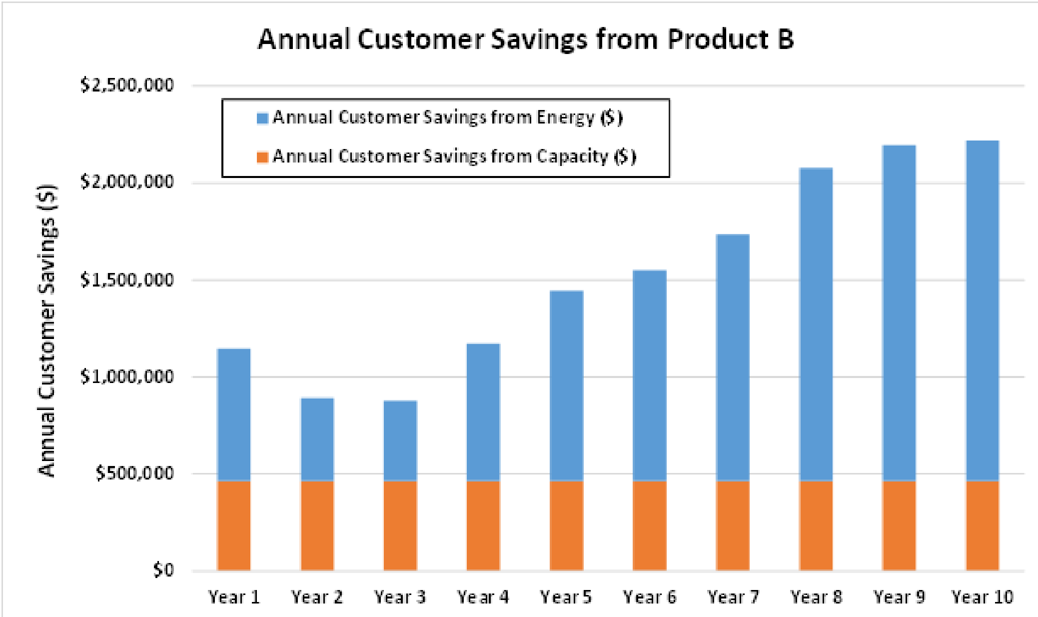
### *D. Estimated Savings*

As MP explained on page 24 of the Petition, it proposes to recover "the retail jurisdictional portion of the maximum $12.6 million total cost of Product B," which staff notes is an annual cost. However, MP calculated Product B could capture $15 million in benefits, in the form of $4.6 million in avoided capital investment and $10.6 million in avoided energy costs.[35]

In the figure below, MP shows the annual customer savings from Product B over a ten-year term.[36] The flat, orange portion is avoided capacity savings, while the blue portion is avoided energy savings:

[35] Petition, at 22.

[36] MP response to PUC Information Request 5.c. (June 17, 2019).




As shown, the estimated $4.6 million in avoided capacity investment (the orange bars above) is slightly less than $500,000 per year for ten years. The avoided capacity benefit is derived by taking the difference between the projected levelized revenue requirements for a new gas combustion turbine (CT) minus the demand credit of Product B over a 10-year period.

The avoided energy benefit is calculated by taking the difference between the levelized variable energy cost for a new gas CT—i.e. the cost to dispatch—and the Physical Interruption Energy Credit over a 10-year period. MP assumes a $41/MWh levelized dispatch cost as the cost of peaking energy over this period, and the $30/MWh curtailment credit remains constant.

To further illustrate how MP projected the roughly $10.6 million in avoided energy benefits, the table below shows MP calculations on an annual basis. (Staff replicated the table from MP's Response to OAG Information Request No. 7 and removed years 2022-2025 for space and readability.) The table shows that the avoided CT dispatch cost (Row A) is always higher than the Physical Interruption Credit (Row B), thus yielding an avoided energy benefit in all years.[37]

[37] MP Response to OAG Information Request No. 7, OAG Comments, Exhibit 8, Page 1 of 2 (February 20, 2019).

| Annual Estimated Savings by Year of Product B | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **2019** | **2020** | **2021** | | **2026** | **2027** | **2028** | **Math** |
| **(A) Avoided Cost – CT Dispatch ($/MWh)** | $37.56 | $34.75 | $34.58 | | $47.92 | $49.23 | $49.50 | |
| **(B) Physical Interruption Credit ($/MWh)** | $30 | $30 | $30 | | $30 | $30 | $30 | |
| **(C) Energy Cost Savings ($/MWh)** | $7.56 | $4.75 | $4.58 | | $17.92 | $19.23 | $19.50 | A - B |
| **(D) Maximum Annual Energy (MWh)** | 90,000 | 90,000 | 90,000 | | 90,000 | 90,000 | 90,000 | |
| **(E) Annual Savings ($)** | $680,579 | $427,533 | $412,533 | | $1,612,456 | $1,730,642 | $1,754,854 | D*E |
| **(F) Total Savings (10 years)** | $10,663,650 | | | | | | | ∑ E |

Row F shows that the annual customer savings arising from Product B will be about $10.6 million. This amount is simply the sum of the stream of savings shown in Row E. Staff notes that the $10.6 million is not discounted to the present value, however. Using the same discount rate that MP used in calculating the levelized cost of the CT, the present value of the annual energy savings will only amount to about $6.8 million, as replicated in the figure below:

| | | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
| Total Savings (Annual) ($) | 34 | | $680,579 | $427,622 | $412,533 | $706,994 | $980,676 | $1,084,778 | $1,272,515 | $1,612,456 | $1,730,642 | $1,754,854 |
| Present Value of Savings | 35 | $6,846,553 | $635,675 | $373,056 | $336,147 | $538,076 | $697,125 | $720,249 | $789,154 | $933,993 | $936,310 | $886,769 |
| | | Discount Rate = 0.070639 | | | | | | | | | | |
| | | C35=SUM(D35:M35) | | | | | | | | | | |
| | | D35 = 680579/(1+0/070639) | | | | | | | | | | |
| | | E35 = 680579/(1+0/070639)^2 | | | | | | | | | | |
| | | F35 = 680579/(1+0/070639)^3 | | | | | | | | | | |
| | | M35 = 680579/(1+0/070639)^10 | | | | | | | | | | |

Of course, the discounted value still shows net customer benefit—strictly in terms of energy cost savings that is—which will be the case so long as the credit given is less than the opportunity cost (Row A); however, the amount is less than MP claims.

## IV. Parties' Comments

### *A. Department of Commerce*

1. Approve Products A and C, Do Not Approve Product B

While in general, the Department is supportive of DSM programs, in this instance the Department opposes approval of Product B because "the benefits appear to be overstated." Overall, the Department argued, the Commission should deny MP's proposed Product B given that the costs of the proposed Product B outweigh the expected benefits.

2. Disallow Recovery of the Demand Credit

In its reply comments, the Department argued that because MP has no capacity need for the foreseeable future, the Commission should disallow MP's proposal to charge any ratepayers for the estimated $12.6 million for demand credits at this time. But, the Department maintains that Minnesota Rules, parts 7825.2390 through 7825.2920, provide for utilities to adjust rates because of changes to costs authorized by the Commission in the most recent rate case. These rules make no exception to include costs of power not purchased. The Department notes that, if the Commission approves Product B, it may be reasonable for costs for Physical Interruption Credits ($30/MWh) paid for economic interruptions to be charged to all ratepayers.

3. If the Commission Allows Recovery of the Capacity Credit, Recovery Should Occur in the Next Rate Case

The Department recognizes that because of the uncertainty as to the actual cost of Product B, MP has preferred to recover the costs through a rider. But, MP has not supported its proposal to recover any capacity costs stemming from its proposal at this time. If the Commission approves Product B, the Department recommends that the Commission allow the capacity costs to be recovered in MP's next rate case. The Department also requires that MP allocate capacity costs between wholesale and retail jurisdictions and among all firm and interruptible customer classes using the energy allocator from MP's last rate case.

4. The Energy Credit Should Not be Recovered through the FPE Rider

However, the Department acknowledges MP's contention that when customers physically curtail energy, MP avoids the need to generate energy or purchase energy from the market, and that the $30/MWh credit replaces the cost of this energy.

The Department notes that while it might make sense to recover these costs through the Fuel and Purchased Energy (FPE) Rider, MP has not requested a rule variance or provided enough justification for its recovery there in the face specific language of what can be recovered through the FPE Rider in Minnesota Rules, parts 7825.2390 through 7825.2920.

The Department maintains that as the costs MP proposes to recover do not fit with Minnesota Rules, parts 7825.2390 through 7825.2920, and as no party has requested a variance of these rules for this recovery, the Department recommends that the Commission deny recovery of the physical interruptible energy credit through the FPE Rider.

The Department points out that a separate rider would be required to recover the energy credit. Again, as previously noted, the Department suggests that MP recover only costs of the Physical Interruptible Energy Credit in the rider net of all revenue from the $5/MWh adder.

5. The $5/MWh Buy-Back Adder should be Returned to Ratepayers

In its initial comments, the Department requested that MP explain whether the $5/MWh buy-through adder would be retained by the Company or returned to customers via the Fuel and Purchased Energy Adjustment. MP responded that the adder would be retained by the Company to account for the portion of fixed costs that are included in the current Large Power firm energy rate. MP estimated that the fixed cost recovery included in the firm energy rate was around $6.78/MWh. MP also noted that in its next rate case the adder would become a revenue credit that would benefit customers.

The Department does not agree with MP's proposal to keep the $5/MWh adder. The Department argues that if the adder is considered to be an increased incentive for participants of Product B not to buy through during firm load control events, then the costs of this adder should be returned to MP's customers to offset some of the cost of the program, if approved.

*B. Advanced Energy Management Alliance*

AEMA is generally supportive of the DR program. The trade association noted and commended MP on a few best practices on pages two through three of their initial comments, mainly:

- Establishing a compensation level for Product B that is close to the long-run cost of capacity;
- Aligning the availability and response requirements for emergency dispatches w/ MISO's requirements;
- Allowing for economic dispatches and buy-through option across MP's system; and
- Developing a clear, transparent tariff rider.

In initial comments, AEMA provided two programmatic recommendations to MP to maximize both participation and public benefits:

- Allow and include an MP-approved DR aggregator(s) to manage customer participation.
- Increase the DR capacity cap from 150 MW to 400 MW. Since MP currently has 250 MW under its existing DR program, AEMA believes that "MP could see a one-for-one shift in participation to the new product."[38] This modification would allow a net new DR and reduce MP's reliance on generation.

*DR Aggregators*

AEMA supported using aggregators for use their technologies, expertise, and business models and to shield customers from risk.[39] Citing DR capacity in the PJM region, AEMA noted that 83% of DR came from aggregators for years 2018-2019. AEMA also suggested allowing MP to qualify "a limited number of aggregators to participate under the tariff or issue an RFP for a single aggregator."[40]

*Increase Participation Cap*

[38] Advanced Energy Management Alliance Initial Comments at 3. (February 20, 2019).
[39] Advanced Energy Management Alliance Initial Comments at 3. (February 20, 2019).
[40] Advanced Energy Management Alliance Initial Comments at 5. (February 20, 2019).

According to AMEA, as it is currently designed, the 150 MW cap will likely result in an overall *loss* of capacity on MP's system. AEMA saw no justification for this limit outside of what was included in the IRP. Therefore, AEMA recommends increasing the DR cap to 400 MW for greater access to this valuable resource under this program.

Based on their experience in other DR utility programs and tariffs, AEMA wished to provide clarification on various misconceptions about the value that DR provides to a system. When evaluating any DR program, AEMA believes the following should be considered: [41]

- DR resources provide capacity value simply by being available during emergencies; MP will also receive accredited capacity under MISO's Resource Adequacy Program.
- Compensation under DR programs should consider the full scope of avoided generation, transmission, and distribution costs, which is an established practice in states throughout the MISO region. MP's program may in fact undervalue its DR resources by focusing only on avoided generation costs to determine their compensation level.
- The enrollment of any capacity under Product B will provide net benefits to all of MP's customers. Every MW of enrollment in Product B will drive more than $30,000 in net benefits across MP's system from avoided capacity costs alone.

The trade association agreed to the product design recommendations made by Fresh Energy to remove the four-hour minimum required duration for economic curtailments and that the existing limit of two firm load control events/days be retained. AEMA also agreed with CUB in establishing a baseline for energy payments and recommended "an adjusted high 4 of 5 baseline" as it currently abides by in the PJM region.[42] This was helpful in evaluating performance and provided greater accuracy and integrity than baselines using averages of usage during hours prior to an event.

Because DR programs in regulated states are typically evaluated on an avoided cost basis, and to highlight additional savings not captured in the existing modeling, in reply comments, AEMA provided a table containing avoided costs typically used to evaluate DSM programs:

*Table 1 – Avoided costs used to evaluate DSM program cost-effectiveness across MISO states*

| | NSP (Xcel) Minnesota[2] | Wisconsin (state-wide)[3] | MidAmerican Energy (Iowa)[4] | NIPSCO (Indiana)[5] | Ameren (Missouri)[6] |
|---|---|---|---|---|---|
| Avoided G costs ($/MW-yr) | $63.00 | $130.26 | $119.47 | $122.92 | 49.80 |
| Avoided T costs ($/MW-yr) | $3.10 | - | $16.77 | $2.42 | 6.40 |
| Avoided D costs ($/MW-yr) | $8.00 | - | $35.83 | $46.32 | 18.60 |
| ***Total*** | *$74.10* | *$130.26* | *$180.15* | *$171.66* | *$74.80* |

[41] Advanced Energy Management Alliance Reply Comments at 3. (March 13, 2019).

[42] Advanced Energy Management Alliance Reply Comments at 7. (March 13, 2019).

AEMA recommended the Commission consider that DR programs provide additional benefits beyond avoided generation capacity when considering the appropriate compensation level, such as avoided transmission and distribution costs.[43] In fact, AMEA views the avoided cost of generation capacity should as a price floor, and AEMA theorized that MP customers may receive an extra 20-50% additional avoided costs savings not included in the proposed program.

### *C. Citizens Utility Board of Minnesota*

For a number of reasons, CUB's recommendation is that the Commission deny MP's DR petition and, instead, defer this decision to their upcoming IRP, which would allow the Commission and stakeholders to review all resources and ensure the correct level and least-cost DR program is chosen.

CUB is concerned with the costs to non-participant customers for this program where they will see little benefit and was critical of MP's claim that customers will save $4.6 million through avoided capacity costs. CUB asserted Product B would increase residential class bills at a rate of 2.1%, depending on the cost recovery method, which is more than the last rate case.

CUB argued that has not demonstrated a need for additional resources on its system. CUB stated that, while they are in favor of DR that saves customers money, reduces emissions, and increases the reliability of the grid, the DR product must provide more value than just being less expensive than a hypothetical combustion turbine generation resource; it must also actually avoid or defer the need for investment in that generation resource:

> Minnesota Power has not demonstrated a need for this resource while simultaneously requesting a comparable resource that would cost customers $126 million. Spending $126 million for the opportunity to pay $30/MWh instead of the average cost of peaking energy cited by the Company of $41/MWh is a terrible bet.[44]

CUB observed that over the course of the record, MP never provided any further information indicating a need for additional resources on their system. If this is true, CUB reasoned, then the avoided capacity benefits of this program are zero and non-participating customer funds will be transferred directly to participating customers for no benefits in return.

Since Product B will rely on program participants to curtail their demand in response to a utility-called event, CUB cautioned there could be inefficient outcomes and raised three concerns:

1. The benefits to all customers are uncertain at this time;
2. This product is not guaranteed to be fully utilized; and
3. The program design allows for participant manipulation for greater incentives.

CUB observed that MP's Petition does not include a minimum number of Firm Load Control hours or events for Product B, which would prevent concern on underutilizing the product and

[43] Advanced Energy Management Alliance Reply Comments at 6 (March 13, 2019).
[44] CUB reply comments, at 3.

also ensure customers see benefits. CUB noted that MP has an existing DR program (Product A), but the utility had not called on participants to reduce load for the period 2014 to 2018.

CUB further stated, "Without any previous experience calling DR events based on economic curtailment, it is very difficult to determine the rate participating customers will decide to buy-through events and take on the $5/MWh adder. Buying-through events further limits the avoided energy and avoided capacity benefits customers will see from this program."[45] CUB is skeptical that the utility will increase DR curtailment from zero up to 600 hours in the first year of the program, and if MP is not able to call more than 600 hours annually, it cannot make up for any shortages later in the program term.

CUB suggested establishing the program with an attainable baseline and increasing the MW commitments annually beginning with 30 MW the first year, then 60 the second, as an example. CUB believes that might negate any concern for program underuse and limiting costs. CUB continued with their request for annual reporting so MP can demonstrate program utilization and benefits to customers. These reports could also inform the IRP process and future, possibly larger, DR program offerings.

CUB also questioned MP's ability to accurately identify energy available for curtailment. Currently, MP's method is the "difference between the customer's firm service level and the higher of the average of four hours before notification or four hours before the interruption period begins."

CUB's first trouble is that "a shorter timeframe to set average load for a [new] participating customer allows for a much higher variation in load that may not be a true representation of that customer's typical load."[46] Second, MP's advance notice of the DR events could allow program participants to manipulate their demand to increase the amount of curtailable load, which would also increase their incentive.

As a solution, CUB suggested MP should use longer time periods from non-event days in order to set an average firm load. CUB referenced EnerNOC/Enel X, one of the largest DR providers in the world, which recommends a period of the previous five non-event business days to set a baseline for an economic DR model. This method provides a more reliable load profile of participants and better represents the total impact the program will have on customers and the grid, while also limiting the ability for manipulation.

### *D. Fresh Energy*

Fresh Energy is supportive of MP's demand response petition and suggested a modification on the operation and reporting related to Product B.

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[45] CUB initial comments, at 5.

[46] CUB initial comments, at 6.

The party focused their comments on Product B, but noted that Product A – the traditional interruptible load called on only during MISO-designated emergencies – has no additional operational value for MP or the system, but does have value for customers not wanting to change operations and should continue to be offered.

Following resource comparisons and considering value to the system, Fresh Energy determined it had no issue with Product B's capacity pricing of $7/kW-month. The party also concluded the energy component price of $30/MWh is reasonable when compared to an estimated peaking energy cost of $41/MWh and after examining MP's locational marginal price (LMP) data at the MP.MP node for years 2015 to mid-2018 highlighting that 2017 was found to have "13% of hours were at or above $30/MWh."[47] In addition, Fresh Energy found that the average of the most expensive 1% of LMPs at the MP.MP node in 2017 was $113/MWh.

Fresh Energy also questioned the need for the minimum four hour period as MP did not reference an operational or policy obligation in their Petition.

> This minimum duration significantly limits the flexibility of Product B in that whenever MP calls on it, the load control must last for at least four hours. As such, the use of Product B cannot be as targeted or nimble, and as such, its opportunity to target the highest cost hours is limited.[48]

Fresh Energy proposed modifying Product B by removing the four-hour duration of the Firm Load Control periods. According to Fresh Energy, "there is no apparent operational or policy reason for the minimum period in the petition."[49]

Fresh Energy also suggested considering a performance incentive using a shared savings mechanism. This would be to encourage MP to maximize Product B's use. Fresh Energy argued that a shared savings mechanism would "align the Company's direct financial interest with its customers' in this specific use-case."

Finally, Fresh Energy further recommended that the Commission require MP to file quarterly reports on (1) when it called Product B, (2) for how much capacity, and (3) the market price avoided for each hour. This aggregated, anonymous data would not only provide transparency, but also accountability that MP is maximizing the value of Product B.

### *E. Large Power Intervenors*

LPI recommends the Commission approve MP's Petition and adopt Cost Recovery Method 2 for Product B. LPI cited the Commission's support for the development of new DR products in MP's rate case, IRP, and NTEC proceedings. LPI further applauded the Company's efforts to work

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[47] Fresh Energy comments, at 4.

[48] Fresh Energy comments, at 5.

[49] Fresh Energy comments, at 5.

with LPI and engage other stakeholders, and it emphasized the long-term value that Product B provides.

On page 2 of its initial comments, LPI summarized its perspective on the proposed Product B:

> In general, agreeing to potential interruptions to electric service for an industrial customer means taking on substantial operational risk. Managing for that risk means making significant modifications to day-to-day operations to account and prepare for a potential interruption. In deciding whether to enroll in the DR program, customers will individually assess the operational risk of enrolling relative to the potential economic benefits. But overall, LPI believes that Minnesota Power has struck an appropriate balance between benefits offered to enrolling customers and overall costs and cost allocation to other ratepayers.

As indicated above, LPI emphasizes throughout its comments the operational realities of large power users who compete in a global marketplace. And energy interruptions can be challenging and can create a significant operational risk for these businesses, which means that there must be an adequate incentive for taking this risk.

LPI was particularly encouraged by the buy-through component of Product B. According to LPI, Product B acknowledges the operational risk for subscribers by providing the flexibility to buy through during a curtailment:

> Many companies may reasonably be able to accommodate an interruption much of the time, but still need to plan for rarer times when an interruption would compromise their ability to make a critical delivery, otherwise cause a serious loss, or create operational challenges depending on the time of year. Having the option to buy through an interruption – even at a premium – provides much more flexibility and makes participation in DR more feasible. Thus, the buy-through component of Product B is a necessary feature for managing the operational risk of potential interruptions.[50]

LPI also emphasized that the product design is the result of extensive input and discussions with large power customers, and thus, making major changes to the products at this stage could potentially derail any appetite large customers might have in Product B:

> If the Commission opts to order changes that would increase the operational risk (e.g., raise the total hours or number of curtailments), reduce the credit levels, or allocate more cost to the large power class this program is unlikely to be successful.[51]

[50] LPI comments, at 8.

[51] LPI comments, at 9.

As noted above, LPI supports Cost Allocation Method 2, which allocates costs based on the Commission's apportionment of the final rate case revenue deficiency by customer class. LPI argued that Method 2 strikes an appropriate balance between system-wide benefits and compensating industrial subscribers for additional risk. LPI added that choosing a cost recovery method that is in line with revenue allocation from the rate case would be fair and consistent with the Commission's order in that proceeding.

Also, LPI argued Method 2 is reasonable because it allocates more cost to the customer classes that contribute more to the need for peaking capacity. LPI quoted MP's explanation that high load factor customers like the Large Power class utilize more energy relative to the required capacity, whereas lower load factor customers like residential and commercial customer classes require higher ratios of capacity relative to energy consumed to reliably serve their needs.[52] A core problem with Method 1 is that, though straightforward, it "fails to reflect the traditional ratemaking principle of cost-causation."[53]

While LPI commended MP's proposal overall, LPI believes there is significantly more DR potential on MP's system than the 150 MW cap. LPI did not expressly recommend the Commission change the cap; however, LPI recommends the Commission encourage the Company to explore expanding the program and consider higher levels of DR in the next IRP:

> Minnesota Power limited its Product B proposal to 150 MW. Again, LPI understands the Company's reasoning and appreciates its commitment to studying higher levels in its next IRP. If the risk/benefit ratio is adequate, LPI believes that there is potential for significantly greater than 150 MW of industrial DR on Minnesota Power's system. Thus, LPI urges the Commission to include the Company's commitment to study expanding DR in its order approving the Petition. Further, the current proposal also only applies to the large power class. Other large industrial customers on Minnesota Power's system (i.e., members of the LLP class) could potentially participate in DR on similar terms and provide additional value.[54]

As noted in the Background section, there is a dispute among the parties on whether there is a demonstrated need for the proposed DR products. In its reply comments, LPI strongly disagreed with parties who argued that need has not been demonstrated. LPI believes the question of need is no longer an issue before the Commission because the Commission has continually instructed MP to explore additional DR options.

### *F. OAG*

#### 1. Commission Should Not Approve the Product B without a Demonstrated Need

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[52] LPI comments, at 11; MP Petition, at 26.

[53] LPI comments, at 11.

[54] LPI comments, at 13.

The OAG maintains that notwithstanding the Commission's requirement that MP file a DR product along with cost recovery proposal, the Commission should not approve the proposed filing without a demonstrated need for the resource.

The OAG argues that the avoided-cost comparison with the 228 MW combustion turbine is unavailing because MP "has not demonstrated that there is any need for the resources it seeks to acquire." Essentially, OAG is arguing that MP's Option B seeks to charge for a resource MP does not need, or has not shown the need for, and that "it would not be reasonable for MP to acquire more resources than it needs to provide service to ratepayers."

The OAG points out that MP's recent IRP filing "did not identify any peaking generation resource" and that MP clearly stated that its model included "150 MW of industrial demand response in the base case," and that MP "did not indicate additional peak resources were required" above that amount. The OAG adds that MP's instant petition states that its existing large industrial interruptible program has provided 100 MW to 260 MW of capacity over the last five MISO planning years.

Based on this information, the OAG contends that that MP's existing DR portfolio satisfies the identified need for DR and peaking resources.

The OAG concludes that because MP has not identified any existing or planned generation investment that would be deferred or offset by the DR product, the OAG is not satisfied that a DR program could avoid $4.6 million in investments when the investments are not needed in the first place.

The OAG advocates that the Commission require MP to demonstrate that there is a need for the DR resources it seeks to acquire, or that the DR resources would offset other, more expensive resources.

2. Capacity-Related Benefits are Overstated

The OAG argues that MP has overestimated the benefits of Product B.

The OAG argues that MP's claim of approximately $4.6 million of avoided investment over 10 years compared to the 228 MW combustion turbine is flawed for two reasons: (1) MP has not demonstrated that there is any need for the resources it seeks to acquire in the first place; and (2) the price that MP is proposing to offer for Product B capacity is unreasonably high.

The OAG maintains that MP has not demonstrated or even attempted to demonstrate that there is any need for the resources it seeks to acquire, or that they would offset any other resources. The OAG adds that its own analysis of MP's existing DR portfolio is that it satisfies the identified need for DR and peaking resources in its most recent IRP and that the new DR products that MP proposes do not appear to be necessary to serve an identified need for DR or other peaking generation resources. The OAG concludes that it is not clear that a DR program could avoid $4.6 million in investments when the investments are not needed in the first place.

The OAG maintains that the residential rate impact (1.3% or 2.1%) is to be viewed in light of the overall rate increase of only 1.79% in the rate case and that, in this context, MP has not justified its proposal to increase rates by up to 2.1 percent for a demand response product for which there is no demonstrable need.

3. Capacity Credit is Over-Priced and Should be Rejected

The OAG asks that the Commission reject MP's filing because MP has not demonstrated that the prices are reasonable.

The OAG argues that notwithstanding MP's derivation of the capacity credit of $7,000/MW by comparison to a 228MW combustion turbine, the $7,000 per MW-month price was not calculated using a specific method, but was negotiated with the large power customers who found it "agreeable." More fundamentally, the OAG points out that the comparison was made when MP does not even own a peaking combustion turbine unit. The OAG concludes that it is not reasonable to set the price for Product B using a resource that MP does not own and does not need.

The OAG points out that, under MP's proposal, in order to reap the capacity benefits of $4.6 million over ten years (less than $500,000 per year), ratepayers would be paying $126 million to Large Power customers over the same period. Even here, "$126 million to obtain $4.6 million in savings does not appear to be a good bet, especially when the 'savings' will only happen if MP's price comparisons are accurate."

4. Capacity Credit Should be Determined under Reverse Dutch Auction

The OAG maintains that there is a risk of the price of a product being too high or too low when the price is determined without the advantage of complete information of the costs and benefits.

The OAG argues that because there is no demonstrated need for the DR project, there is considerable time to try a reverse Dutch auction where the buyer of resource (MP) initially sets a low price and then raises it until sellers (large industrial customers) agree to provide the quantity of service requested.

The OAG recommends that the Commission initiate the reverse Dutch auction with an initial bid of $3,500/MW-month.

The auction would proceed with the 150 MW threshold as the desired quantity. The OAG also recommends that he Commission require MP to report on Product B subscriptions in three months. At that time, the OAG notes that the Commission could determine whether the amount of demand response provided by customers is sufficient. If the response is determined to be inadequate, the price can be incrementally raised until the desire amount of the product is offered by the customers.

5. Energy-Related Benefits are Overstated and Could be Unavailing

The OAG acknowledges that MP can curtail up to 90,000 MWh (150 MW times 600 hours) each year at a cost of $30/MWh and that MP has estimated a maximum of $10.6 million in avoided energy costs over 10 years. However, the OAG notes that whether or not those benefits are captured depends entirely on MP's performance and its decisions about when to call for interruptions.

The OAG stresses that the $10.6 million in avoided energy costs is actually the maximum possible benefit when MP interrupts 90,000 MWh per year for ten years in a row. The OAG notes that this is unrealistic because there does not appear to be any particular reason to believe that MP will do so, which suggests that the actual avoided energy costs could be much lower than $10.6 million.

The OAG contends that MP has no particular reasons to curtail energy for so long and, consequently, the actual avoided energy costs could be much lower than $10.6 million.
The OAG suggests that MP has relatively little incentive to call 90,000 MWh of economic interruptions each year and that, although an economic interruption could be triggered when the anticipated incremental cost is higher than the credit of $30/MWh, the tariff proposed by MP does not require MP to call for interruption.

The OAG pointed out the likelihood of this product creating a perverse incentive for MP to not call a curtailment – that is, if MP determined not to call an economic interruption, it would continue to recover the higher energy costs through the fuel clause adjustment. The OAG also suggests that MP may face pressure, implicit or otherwise, to avoid interruptions of its largest customers.

6. Product B Transfers Wealth from Other Customers to Large Industrial Customers

The OAG maintains that the estimated capacity benefits of $4.6 million over 10-years would require MP's customers to pay $126 million to Large Power customers over the same period.

The OAG maintains that paying $126 million to obtain $4.6 million in savings does not appear to be a good bet, especially when the "savings" will only happen if MP's price comparisons are accurate.

The OAG argues that the large power customers will win in every situation because they will receive $126 million in capacity credits over ten years for a capacity resource that is not needed, and which is unlikely to ever be curtailed by MISO.

The OAG also points out that it is possible that all 150 MW of Product B may be filled by customers who are currently subscribing to Product A-type offering and transfer (tariff-shop) their DR product away from Product A. That is, the OAG notes that creating 150 MW of Product B DR will not provide much benefit to the system if it means 150 MW less of Product A DR and that, in fact, that would harm ratepayers because the 150 MW of Product B would cost 1000 percent as much as 150 MW of Product A.

The OAG added that the value of the ten-year agreement is somewhat questionable because customers on Product B would have the opportunity to convert back to firm service at any time by giving only 90 days' notice

7. Recovery of Energy Credit through the Fuel and Purchased Energy Adjustment Rider

The OAG's position is that if the Commission approves MP's proposal to recover the Physical Interruption Energy Credit through the Rider for Fuel and Purchased Energy Adjustment (FPEA), the costs would be collected using the same per kWh rate for all customer classes, and there would be no dispute.

If, however, the Commission approves the DR product but denies MP's request to recover the Physical Interruption Energy Credit through the FPEA, then the Commission will have to determine a different cost recovery method.

8. Recovery of Demand Credit

The OAG disputes recovery of the demand credit because it contends neither of the two methods proposed by MP are reasonable.

The OAG maintains that MP's proposals for recovery of demand credits would allocate the costs of Product B only to firm customers, shielding interruptible customers—all of whom are Large Power customers—from the costs of the DR resource.

The OAG argues that MP's rate proposals favor the large industrial customers in stages, first, by excluding the "consumption from Large Power/Other customers." Then, the OAG contends that MP removes "a portion of the consumption of Large Power customers who would participate in Product B when calculating the per kWh rate."

The consequence of these exclusions "increase the rate paid by other customers, because they reduce the amount of consumption that the costs are spread over, and indicate that MP does not intend to charge Large Power/Other or Large Power Product B customers at all for the costs of Product B." The OAG contends that there is no reasonable basis for MP's proposal to exclude interruptible customers from the costs of Product B.

The OAG objects to MP's Rate Recovery Method 2 because MP used the allocation method based on the Commission's apportionment of the final rate case deficiency by customer class.

The OAG argues that MP's proposal allocates DR costs on only the incremental rate increase, not the actual revenue apportionment. While the former method allocates 34.18% (see the table below) of the costs to the large industrial customers, the latter method allocated 51.39% of the costs to the same customer class:

| | Actual Revenue Apportionment | | | Incremental Rate Increase | |
|---|---|---|---|---|---|
| | **Final Rate Revenue** | **Percent of Total Revenue** | | **Revenue Deficiency** | **Percent of Rev. Def.** |
| **Residential** | $104,917,231 | 15.40% | | $5,547,926 | 29.62% |
| **General Service** | $69,061,214 | 10.14% | | $2,335,403 | 19.5% |
| **Large Light & Power** | $117,008,202 | 17.18% | | $1,814,752 | 15.15% |
| **Large Power** | $350,067,353 | **51.39%** | | $4,094,217 | **34.18%** |
| **Lighting** | $3,545,005 | 0.52% | | $0 | 0% |
| **Duel Fuel** | $10,538,568 | 1.55% | | $185,342 | 1.55% |
| **Large Power Other** | $26,073,817 | 3.83% | | $0 | 0% |
| **Total** | $681,211,390 | | | $11,977,640 | |

The OAG maintains that the Commission does not set rates based only on the revenue deficiency and that it determines a revenue apportionment based on all of the utility's costs.

The OAG recommends that the Commission adopt a uniform rate, comparable to the rate derived by MP under Recovery Method 1, but after making the following modifications:

- include consumption of large power/other customers in the rate calculation; and
- do not exclude the Large Power Product B consumption from the calculation.

If the Commission approves Product B, the OAG recommends the following rate for recovery of demand credit:

| | Amount |
|---|---|
| **Recovery Target** | $12.6 million |
| **Retail Recovery target (84.360%)** | $10.6 million |
| | |
| **Test Year Usage (Firm)** | 8,864,975 MWh |
| **Test Year Usage (LP/Other)** | 603,570 MWh |
| **DR Billing units** | 9,468,545 MWh |
| | |
| **Flat Rate for all Customers** | $0.001123/KWh |

### *G. Department Response to Parties*

#### 1. OAG's Cost Recovery Proposal

The OAG proposed that costs should be recovered from interruptible customers, as well as firm customers, as all customers benefit from the proposal. This approach is consistent with how costs of a new power facility would be recovered if one were built. MP clarified that only the portion of the load that interruptible customers had associated with Product B would be excluded from cost recovery and the rest of the customer's firm load would have the costs of the Demand response products recovered from them. Since MP has no capacity need at this time, the Department concluded that ratepayers should not be charged the estimated $12.6 million, but it may be reasonable for the Physical Interruption Credits to be paid by all customers if the Commission approves Product B.

#### 2. Allocation of Cost Recovery

The Department provided analysis on the two cost recovery allocation methods proposed by MP for Product B: Flat per-kWh charge from all firm customers OR rate case apportionment.

The first cost recovery method the Company proposed was a flat per-kWh charge for all firm customers regardless of class, while the second allocation focuses on allocating costs between industrial and other customers based on the Commission-approved allocation of the revenue deficiency from MP's last rate case. The Department requested that MP provide additional information regarding the rate impacts to a customer on Energy Intensive Trade Exposed (EITE) pricing and Product B before it would make a recommendation on allocation. Believing that MP has not established a need for capacity, the Department later recommended that the Commission deny recovery of the $12.6 million in capacity costs and does not recommend use of the D-01 allocator to allocate costs between wholesale and retail customers as proposed by MP. The Department recommends the following should the Commission approve Product B:

1) recover only costs of the Physical Interruptible Energy Credit in the rider net of all revenue from the $5/MWh adder discussed above and

2) use of the energy allocator from its last rate case to allocate costs both between wholesale and retail customers and among retail customer classes, including interruptible classes, for non-participating interruptible customers and participating customers that choose to buy through an interruption.

#### 3. DR Aggregation

Without knowing the costs of AEMA's DR aggregation proposal and the impacts it would have on program participation given MP's customer profile, the Department concluded there is the potential to "improve Product B by allowing customers participating in Product B to respond more flexibly" and "has merit, but should be explored further if the Commission chooses to approve the Company's Product B proposal."

4. Program Manipulation

Both CUB and AEMA flagged concerns regarding participants manipulating the program by increasing their load after they have received a notice of an event, but prior to the event being called. The Department agreed with CUB's recommendation. If the Commission approves Product B, then the Department recommends that the Commission adjust the product in a fashion similar to that which CUB or AEMA proposes.

5. Minimum Period for Product B

Fresh Energy recommended that Product B be modified to remove the four hour minimum firm load control duration period to allow MP more flexibility in calling events for their highest cost hours. The Department agreed that shorter periods would allow MP to target the most expensive hours, but warned that some customers may not be able to respond to a short interruption, which may lead to more customers buying through events, which would in turn reduce any environmental benefits of the program. "The Department is not necessarily opposed to removing the minimum period, but believes there could be unintended consequences in doing so."

*H. Large Customer Comments*

Verso Corporation, which is the owner of the Duluth Paper Mill, and Blandin Paper Company both filed comments supporting MP's DR product. Verso noted that its electric rates have increased more than 60% since 2007, which puts the Mill at a competitive disadvantage. Blandin noted the challenging global marketplace and trade production risk and stated the proposed DR product is an opportunity to enhance its competitiveness.

*I. MP Response to Reply Comments*

MP's June 28, 2019 supplemental response largely addressed some of the concerns raised by the Department. The Company's response does not necessarily come to the Department's side on their concerns, but MP was willing to go along with some of the Department's recommendations.

For example, the Department raised concerns about where the money from the $5/MWh buy through adder would go. MP's initial intent was for the $5/MWh adder to be retained by the Company to account for the fixed costs included in the Large Power firm energy rate, which would become a revenue credit to benefit customers in a future rate case. However, MP agreed to revise the proposal to allow the $5/MWh adder to be returned to customers to offset the costs of the program.

Also, the Department argued that since the Company did not request a rule variance, it should not be able to recovery the physical interruptible energy credit through the FPE Rider.[55] At

[55] Minnesota Rules, parts 7825.2390 through 7825.2920 state that utilities are able "to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the commission in the utility's

first, MP disagreed with the Department's assessment and did not believe a variance to the FPE Rider was necessary, but in its supplemental response the Company stated it "is agreeable to the Department's suggestion to recover the physical interruptible energy credit through a separate rider."[56]

Finally, MP addressed the Department's concern, which was first raised by CUB, that there could be the potential for participants to manipulate their load during the four-hour notice period in order to increase their credit amount.[57] The Department and CUB recommended using a longer time period of non-event days to set an average firm load.

MP stated it is willing to adjust the program to reflect the average of five non-event business days; however, the Company noted, "the operational realities of ramping up large industrial operations like mining and paper production have financial, safety and operational business risks that customers are unlikely to take for a small financial benefit in their demand response program compensation on their electric bill."[58]

### *J. LPI Response to Reply Comments*

LPI reiterated in its response to the reply comments that the question over whether there is a capacity need for 150 MW of DR is misplaced based on the Commission's previous orders. According to LPI:

> The Commission has unambiguously ordered Minnesota Power to submit a DR proposal for its review and did not condition that direction on any further capacity or need-based assessment.[59]

LPI also objected to the Department's recommendation that, if the petition is approved, cost recovery should be deferred to MP's next rate case. LPI believes the Commission was clear that costs should be recovered through a rider and that waiting until the next rate case creates unnecessary and problematic uncertainty and delay.

LPI opposes OAG's proposed "Dutch auction concept" (where the capacity price is set at a low number and incrementally increased every three months until customers subscribe) because it is unworkable. LPI argued that the $7,000/MW-month credit likely is the minimum level needed for many large power customers to justify the risk of participating in Product B. And since large power customers will not subscribe at lower prices, it will take almost two years to reach the current $7,000/MW-month amount.

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most recent general rate case."

[56] MP supplemental response, at 3.

[57] MP explained that "[t]he expected available energy for physical curtailment, or the buy through, is the difference between the customer's firm service level and the higher of the average of four hours before notification or four hours before the interruption period begins."

[58] MP supplemental response, at 2.

[59] LPI supplemental response, at 3.

Responding to the Department's recommendation for the demand credit to be recovered in a rate case, LPI argued the Department's proposal is contrary to the Commission's directive and would significantly delay implementation of Product B.

## V. Staff Analysis

### *A. Analysis of Product B*

#### 1. Has the need for DR been established?

Various parties provided quite different views of whether the "need" for new DR products has already been established by previous Commission orders. A few examples are provided below:

- MP: "Minnesota Power believes the need for a DR resource and the Commission intent for the Company to develop a DR program is clearly defined and articulated through the three dockets referenced above: the 2015 IRP, the 2016 Rate Case, and the 2017 NTEC proceeding."

- LPI: "The need for DR is not before the Commission in this proceeding. The Commission has continually instructed Minnesota Power to explore additional demand-side management options—including in the Company's 2015 integrated resource plan, the Company's 2016 rate case, and most recently in the Nemadji Trail Energy Center ("NTEC") proceeding. In the rate case and NTEC proceedings, the Commission specifically directed Minnesota Power to 'develop a demand-response rider and corresponding methodology for cost recovery.'" (Citations removed.)

- Department: "MP's 2015 IRP did not identify 150 MW of DR resources in the base case … In addition, in the NTEC proceeding [the] Commission did not approve 150 MW of DR … Additionally, while the Commission approved MP's acquisition of a Combined Cycle plant in the NTEC proceeding, based on record support for the construction of the NTEC facility, the Commission did not find there to be any new need for peaking resources for MP."

- OAG: "MP's existing DR portfolio satisfies the identified need for DR and peaking resources in its most recent IRP. The new DR products that MP proposes do not appear to be necessary to serve an identified need for DR or other peaking generation resources. Similarly, MP has not identified any existing or planned generation investment that would be deferred or offset by the DR product."

- CUB: "The responsibility is on the Company to prove that there is a need for additional resources on its system and Minnesota Power did not meet that obligation in this filing … because if the Company is long on capacity, the avoided capacity benefits from this program are zero."

Although there is strong disagreement on the question of need, staff believes all parties made valid points; for instance, MP and LPI are correct that the Commission has, through several orders, directed the Company to work with its large industrial customers to develop and request approval for a new DR product, and MP's petition is indeed complying with what it has been directed to do. The OAG, the Department, and CUB are correct (in staff's view) that MP is long on capacity, and the proposed Product B is limited by the fact that its design is based on a hypothetical resource which does not exist and is not planned to exist on MP's system.

In fairness to the Company, while some cite the lack of new peaking resources in the IRP and NTEC proceedings as evidence why new DR should be rejected, it could be argued that neither the IRP nor NTEC dockets ever fully vetted the value DR can have on MP's system. While it is true that MP's approved IRP includes no incremental peaking resources, one could view those proceedings as incomplete in their ability to provide sufficient evidence to determine whether Product B is a prudent DR resource. In the NTEC proceeding in particular, the question of need for new DR resources was purposefully set aside, and the ALJ Report the Commission adopted stated, in part:

> 511. The record in this proceeding is not sufficiently developed to make a determination on a demand response rider and corresponding methodology for cost recovery.
>
> 512. In addition, both Minnesota Power and LPI have acknowledged that since the 2016 Rate Case Order referral, the parties have continued to engage in thoughtful informal discussions outside of this proceeding. Both parties acknowledged each party's commitment to continue working on this developing a demand response product.
>
> 513. Moreover it is possible there are other persons and organizations beyond the parties to this proceeding who may wish to provide input on such a proposal.
>
> 514. For these reasons, the Administrative Law Judge recommends that the issue be addressed in a new miscellaneous docket.

The Department recommended denying Product B in part because the Commission did not specifically approve 150 MW of DR in the NTEC proceeding. But in one sense, the record in the NTEC proceeding was undeveloped as it pertains to new DR products because new DR was determined to be immaterial with respect to whether or not NTEC is a cost-effective resource.

Also, the Department's analysis of DR in the NTEC proceeding was criticized for not being reflective of how DR exists in the marketplace. The Department considered additional DR resources by making them available to the model "in small quantities (2 units of about 7 MW each) early in the expansion plan," and compared larger-sized DR to a 200 MW CT unit as a proxy.[60] The Department's argument in this case is that since a 200 MW CT was not selected in Strategist, Product B is not needed. Of course, this could be a reasonable way to assess Product

[60] Rakow Surrebuttal, at 41.

B, but it is debatable whether the Department's CT proxy method for examining DR truly reflects the merits of Product B in this case.

At the same time, MP clearly views the CT proxy method as reasonable because that was the basis for how the Company designed Product B. In addition, MP's argument that the need for 150 MW of new DR was established simply because that amount "was included in the base case of the Strategist analysis in the NTEC proceeding"[61] is an overly narrow view of that record.

First, if DR was determined to be outside the scope of the NTEC proceeding, then the Commission's NTEC order is not the proper basis to justify the need for 150 MW of new DR.

Second, the 150 MW value MP references was simply a base case assumption, which also happens to be a roughly 100 MW *reduction* of total accredited DR capacity on MP's system; base case assumptions, by themselves, are not a demonstration of need.[62]

Third, MP ran scenarios in the NTEC proceeding that considered additional levels of DR, and MP modeled incremental DR with similar assumptions as Product B (although it has slightly higher capacity costs and slightly fewer curtailable hours). MP explained in rebuttal testimony:

> Minnesota Power performed a revised Step 1 analysis where 300 MW industrial demand response was available as a resource alternative starting in 2025. The base 150 MW of industrial demand response was removed from Strategist starting in 2025. Then two 150 MW blocks of demand response with 400 curtailable hours at $9.50/kW-month were made available as alternatives starting in 2025 and throughout the rest of the study period. The results show the proposed 250 MW [NTEC] capacity being selected in 83% to 96% of the cases depending on the level of incremental energy efficiency assumed in the base case. A 150 MW block of industrial demand response was selected in approximately 78 percent of the cases; although, in almost all cases it was selected post-2025, after the current proposal was selected. The results clearly showed 250 MW capacity purchase is a superior resource for meeting customer capacity and energy needs compared to industrial demand response.[63]

Fourth, as will be discussed in the next section, MP's new DR proposal does not appear to increase total DR on MP's system, so equating MP's proposed DR products to new a peaking resource on MP's system is questionable to begin with. And there is a separate question of

[61] Petition, at 10.

[62] In the NTEC proceeding, the Department's model assumed "the minimum amount [of DR] within the historical range" of 100 MW-260 MW of DR. The Clean Energy Organizations recommended the ALJ rely on a 192 MW (five-year historical average) assumption of DR resources, which supported their view that MP did not have a need for any new resources. Therefore, MP's 150 MW base case was simply a value in the middle of a range of other assumptions, and the DR assumption, when considered by the ALJ, was scrutinized based on how historical DR should be used to forecast a future need for new resources. But it did *not* originate by Commission order.

[63] Docket No. 17-568, *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Palmer Rebuttal, at 86-87.

what impact the 150 MW of DR would have on the expansion plan. For instance, MP argued repeatedly in the NTEC proceeding that even using 150 MW of DR in the base case, NTEC was frequently selected *in addition to* the DR. Thus, to presume DR would necessarily offset or delay other resource additions runs contrary to how resource planning operates.

For these reasons, staff agrees with parties who argue that resource planning analysis generally should inform whether there is a need for new DR. Having said that, the issue is more nuanced. MP's DR proposal, while analyzed to some extent in the IRP and NTEC proceedings, has either been directed to be analyzed further (IRP) or determined to be outside the scope of the Commission's decision (NTEC). Thus, staff believes MP is complying with previous Commission orders by bringing forward a proposal for new DR resources, and there are limitations on both sides of the argument to base the justification for new DR solely on the outcomes of those proceedings.

2. Is the rate design reasonable?

Regardless of whether a need for the DR products has been established, MP's proposal must still meet the requirements of Minn. Stat. § 216B.03, which states:

> **216B.03 REASONABLE RATE.**
>
> Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers.

Staff agrees with the parties that a 1-2% rate increase on non-participating customers is significant for a new DR resource, where both the need is questionable and total amount of DR on MP's system might not change. The OAG made the observation that "MP's most recent rate case resulted in an overall rate increase of only 1.79 percent,"[64] and staff believes this is worthwhile context.

The back-and-forth over need, in staff's view, would likely be far less significant if Product B indicated a clear ratepayer benefit. The obvious problem is the magnitude of the demand credit, and the ultimate issue here is that $126 million in payments to large power customers over ten year is unjustifiable to some.

LPI argued that the $7,000/MW-month demand credit "is the minimum level needed for many large power customers to justify the risk of participating in Product B and make the effort needed to adapt their operations."[65] Staff interprets this to mean (a) there is little to no room for reductions to this amount and (b) there are good reasons to conclude that the basis for the Product B credit was that it was the price that the large customers wanted. So even if the

[64] OAG comments, at 9.

[65] LPI reply comments, at 4.

Commission agrees with MP and LPI that the need for the DR was previously established, this does not mean the Commission must automatically approve whatever MP proposes, and the Commission may instead find that non-participating customers should not have to subsidize large power customers' risk tolerance.

3. Is the cost-benefit analysis reasonable?

One way to determine whether the rate design is reasonable is by assessing the credibility of MP's estimates of avoided capacity and energy costs. MP maintains that DR products provide system-wide benefits in the same way any other resource does, so the program costs should be compared to the avoided cost of building new generation infrastructure.

Regarding the avoided capacity costs, first, there is no indication that total DR will increase at all from the current 263.1 MW level—it will seemingly just change in form. The emergency event component of Products A and B will remain essentially the same as what MP currently offers, and MP will not receive additional accredited capacity for the Firm Load Control periods in Product B.

Staff agrees with AEMA that "MP could see a one-for-one shift in participation to the new product,[66] and MP appeared to confirm this, stating that the 150 MW cap in Product B would "displace" current DR, not add to its current amount:

> The Company expects the 150 MW of the newly proposed DR Product B will displace a portion of the 250 MW of DR received today in the one year commitment product.[67]

This said, the long-term commitment aspect of Product B might bring more stability to MP's accredited DR, which has fluctuated over time. As a result, MP could modify its long-term DR forecasts it uses in IRP, which would be based on what MP has under a ten-year contract and what it forecasts for Product A. In the immediate term, however, it appears MP will have about the same MISO-accredited DR capacity, so there is no supply-side resource the new DR products will actually avoid.

Regarding avoided energy benefits, MP explained that the $30/MWh credit to participating industrial customers is reasonable because "the cost of energy (fuel + variable O&M) from peaking generation is projected to be greater than the $30/MWh curtailment credit," and "it is more economical for customers to pay the $30/MWh curtailment credit than the cost to procure peaking type energy."[68] Again, this estimate is not based on any existing unit, which MP explained in response to OAG Information Request No. 7:

> It is important to note that **the annual energy savings is the theoretical delta** between the estimated costs to dispatch a modern combustion turbine (CT) and

[66] Advanced Energy Management Alliance Initial Comments at 3. (February 20, 2019).

[67] Petition, at 7.

[68] Petition, at 20.

> the $30 per MWh Physical Interruption Energy Credit paid to customer for interrupting energy under Product B.[69] *(Emphasis added by staff.)*

The Commission could reasonably determine that comparing the Physical Interruption Energy Credit to the dispatch cost of a hypothetical CT (which is currently nonexistent on MP's system) fails to establish the reasonableness of the energy credit. However, as staff will discuss in the next section, the Commission could consider other approaches to finding the value that long-term DR commitments could have for MP's system, and perhaps there reason to believe the hypothetical CT undervalues the Firm Load Control periods.

4. Value of Demand Response

As stated in the previous section, basing the avoided capacity and energy benefits—which is to say, estimating the customer savings—on a nonexistent gas plant has obvious limitations. However, this does not mean that Product B will have no benefits at all. To the contrary, while staff shares the concerns of many of the opposing parties, at the same time staff believes that Product B incorporates a number of good ideas:

First, staff believes the long-term commitment aspect of Product B will be valuable. MP's historical accredited DR capacity, while on the one hand shows that MP might not receive any incremental capacity value as a result of the proposed products, also shows that MP has experienced significant changes in accredited DR on a year-over-year basis. In the Petition, MP noted the value of more long-term DR certainty:

> It is important to note that today Minnesota Power does not have 150 MW of DR capacity under contract for the long-term, as the current industrial DR program is administered through individual annual commitments from customers. The proposed Product B will firm up the 150 MW of capacity as industrial customers are able to commit to make it available for a ten-year period.[70]

Several opposing parties point to the fact that MP is long on capacity as justification to deny Product B. This is a fair critique. But it can also be debated how a utility's near-term net capacity position should influence the determination need for new DR. For instance, there are number of statutes and policy objectives that encourage load management generally. Almost two-thirds of MP's energy sales are to nine customers, so it makes sense, at least conceptually, for MP to consider energy curtailment with a large power customer focus. Additionally, all investor-owned utilities operating in Minnesota have surplus capacity in the near-term. Does this mean that Minnesota utilities should not be pursuing new DR at all?

At the very least, the proposed ten-year period of the ESAs might create more certainty in the availability of DR as a long-term system resource, which will in turn be incorporated into MP's long-term load & capability assessment for resource planning. It could be argued that opposing

[69] OAG comments, Exhibit 8, Page 1 of 2.

[70] Petition, at 10.

parties might be undervaluing the long-term aspect of Product B by essentially using MP's current capacity position as the determining factor of need. If MP cannot have confidence that one-year interruptible agreements will be continually renewed, then there can be less confidence in the availability of DR resources in general. The counterargument to this is that the purpose of resource planning is to measure this value and capture this uncertainty in the scenario analysis in an IRP, so the value the long-term commitment aspect of Product B is an IRP issue.

Second, staff believes the energy-related component (Firm Load Control) of Product B is likely to help manage system costs. MP explained that it "will implement the energy curtailment provision in Product B during periods of high demand or when intermittent renewable generation is unavailable,"[71] which adds functionality to MP's system. As stated before, MP's current DR riders are emergency-only agreements that respond to MISO system peak conditions. Product B is at least conceptually similar to a CT[72] in a way that MP's existing interruptible programs are not by allowing up to 600 hours per year than can be called for economic reasons.

Third, relatedly, staff sees the value in MP's proposal to implement DR beyond only MISO-triggered events, in part because it is a winter-peaking utility. MP explained that an economic interruption will be based on MP's forecasted incremental cost at the MP.MP load zone, and economic interruptions will depend on whether Product B is the most economical resource. [73] While for the Petition, MP used a $41/MWh CT dispatch cost to measure the benefit of the Physical Interruption Energy Credit, a more realistic use for Product B could be to avoid expensive market energy, which has the potential for savings much greater than $41/MWh.

For instance, Fresh Energy noted that, in 2017, the average price of the most expensive hours at MP's locational marginal price node (MP.MP) was the following:

- Most expensive 0.5% of hours was $143/MWh
- Most expensive 1% of hours was $113/MWh
- Most expensive 2% was $86/MWh
- Most expensive 600 hours (the amount of hours MP is able to call Product B) was $56.89/MWh

Also, just because MP has surplus capacity does not mean MP has no market exposure. According to the Department's analysis in the NTEC proceeding, MP is quite exposed to the spot market. For example, the Department's risk analysis estimated there were "400 hours where MP is expected to have a capacity deficit of at least 401 MW."[74] And, the Department

[71] Petition, at 20.

[72] For example, Product B is allowed to curtail up to 90,000 MWh per year, and 90,000 MWh is about the equivalent megawatt-hours of a 200 MW gas CT operating at a 5% capacity factor (200 MW*8760 hrs*0.05 = 87,600 MWh).

[73] OAG comments, Exhibit 11, MP response to OAG Information Request 29.

[74] Docket No. 17-568, In the Matter of Minnesota Power's Petition for Approval of its EnergyForward Resource Package, Ex. DER-8, SRR-4 at 19 (Rakow Direct).

further concluded, "during on-peak hours with minimal wind resources available, MP will only have demand response as a mitigation measure for price spikes."[75]

Overall, MP, as a winter-peaking utility with a high load factor and almost no peaking generation, staff believes a year-round product like Product B has value to MP's system. Staff also believes it is inevitable that the type of DR MP proposes with Product B will come at a higher cost relative to emergency DR. Consider, for instance, that MP's existing interruptible offering has a maximum of 20 hours of curtailment per year—there are five emergency events per year with a four-hour maximum for the duration of the event. By contrast, Product B has a maximum of 600 hours of Firm Load Control hours with a maximum of 12 hours per day. The two types of DR products are simply not comparable in terms of how they require large customers to manage their load.

To be clear, these are not justifications for the substantial price of the demand credit; the point is that participation in Product B—with up to 600 hours of Firm Load Control per year—would require a completely different way for a large industrial customer to manage its business relative to the current interruptible rate, which has rarely been called. Therefore, it is to be expected that Product B will require higher compensation to large customers than Product A. By having large power customers with varying degrees of willingness or ability to adapt their operations—and with perhaps new automated infrastructure required—the trade-off for more load control is higher compensation, which is to say, higher rate impacts. With this being said, as other parties argued, staff believes the Commission can reasonably conclude that the compensation to large power customers is exceedingly high and outweighs the value Product B may provide to the system and, in particular, non-participating customers.

5. Examination of DR in the Next IRP

Given their comments in the NTEC proceeding, all parties should be in agreement that MP has no capacity need in the near-term. (For instance, MP stated its capacity shortfall will not occur until 2025, and LPI and the clean energy advocates stated there is no near-term need for additional capacity at all.) Staff appreciates where LPI and MP are coming from as it pertains to need being a settled issue, but one simply cannot ignore the resource capability MP has on its system. As stated above, staff agrees with MP and LPI that the Physical Interruption Energy Credit in particular could have substantial benefits as a risk-mitigating resource, although staff agrees with the Department, OAG, and CUB that the proposed $7,000/MW-month demand credit arguably lacks justification.

Also, the underlying justification for the demand credit—the avoided investment in a CT resource—might be a bit of sleight of hand; as the comments from Verso Corporation and Blandin indicate, Product B serves to assist large customers in a competitive market, which is not to say Product B is inherently unreasonable, only that what is left unsaid is the DR product is more like an economic assistance rate for large customers than it is an environmentally-responsible DSM product deployed to avoid fossil fuels.

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[75] *Id*.

Looking long-term, however, it's quite possible that greater enrollment in Product B could help offset the need for thermal generation, as the future and perhaps replacement of MP's Boswell 3 and 4 resources will be under examination in the Company's next IRP. As stated previously, one-year agreements carry a lot of long-term uncertainty, and 10-year ESAs for interruptible load could produce more certainty for long-term planning.

All of this is to say the Commission has time to revisit MP's possible acquisition of new DR in the Company's next IRP, which is scheduled to be filed in October 2020, in light of the possible closure of MP's remaining coal units.

### *B. Analysis of Product C*

Staff agrees with the OAG that the Commission should deny Product C without prejudice. This is largely because Product C is too vaguely described. In its 30-page Petition, MP dedicated less than one page to describing Product C, and not at all in the "Cost Allocation, Cost Recovery, and Rate Impact" section.

The OAG submitted its initial comments on February 20, 2019. In those comments, the OAG had a number of sharp criticisms about Product C, characterizing it as "ambiguous" and "not sufficiently clear or precise to result in a rate tariff." The OAG also contended that MP "has not provided any rates, costs, or terms for Product C," and, moreover, "MP has provided so little information about Product C that appropriately balancing [ratemaking] interests should lead to rejection."[76]

Yet, despite these remarks, MP did not address the OAG's concerns in its March 13, 2019 reply, which staff views as a red flag as it pertains to ensuring the record clearly and sufficiently supports what the petitioner requests the Commission approve.

The Department recommended approving Product C, but did not elaborate on how Product C would actually work. Instead, the Department agreed with MP that Product C would be reasonable because "any negotiated contract must be approved by the Commission prior to implementation."[77]

In staff's view, the fact that there is a provision that Product C will be subject to regulatory approval in inadequate to address the lack of detail regarding the proposed product. This is because once the Commission determines that Product C is a reasonable DR product, it might imply that the Commission thought at one time that Product C was a good idea. Staff (and it appears OAG) has no idea how Product C will work, cost or benefit anyone but those engagement in the transaction.

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[76] OAG comments, at 18.

[77] Department comments, at 7.

*C. Analysis of Product A*

Staff does not object to approving Product A; there does not appear to be any harmful risk in basing Product A on capacity prices in MISO Local Resource Zone 1. As shown in the table on page 18 of the briefing paper, which compares Product A to the current Replacement Interruptible Service program, this is apparently what MP currently does anyway. Thus, Product A simply reflects what is already in existence, and MP noted that the rates are already accounted for as a result of the Commission's decision in MP's 2016 rate case.

If the Commission denies approving Product B and Product C, however, staff is also unsure what value there would be in approving Product A.

*D. Rate Design and Cost Recovery for Product B*

1. Rate Design

As discussed in the "Parties' Comments" section of the briefing papers, the Department does not support approval of Product B. However, if Product B is approved, the Department does not support establishing a rider for recovering capacity costs and instead recommends that the recovery of costs would be better done though MP's next rate case.

In response, LPI noted that the Commission specifically directed stakeholders in its NTEC Order "to develop a demand-response rider and corresponding methodology for cost recovery."[78,79]

With the benefit of an actual DR proposal, the Commission can of course take a different position and decide it would be best if costs associated with Product B should be recovered in a rate case. However, staff agrees with LPI that the Commission gave clear direction for MP to propose a DR rider with corresponding cost recovery. In other words, staff believes MP's proposed rider and cost recovery request reflects what the Commission asked of the Company.

2. Allocation Method 1 versus 2

In comparing Cost Allocation Method 1 to Method 2, staff agrees with the OAG that Method 1 is more equitable and aligns with several rate design principles.

MP has advanced the rationale that paying for the proposed demand credits is more economical than bearing the cost of a new peaking 228 MW combustion turbine. Because a new generating plant confers benefit on all customers, Product B should also benefit all customers. As all customers are benefited, the rate design should spread the cost of Product B across all customers.

MP's Recovery Method 2 recovers 34.182% of the $10.6 million cost from the Large Power customer class and the remaining 65.818% from all other customer classes. This allocation,

[78] LPI reply comments, at 7.

[79] NTEC Order at 23 (emphasis added).

approved by the Commission in MP's rate case (16-664), reflects all of the considerations specific to the rate case and may not be relevant to the calculation of the rate additive in this rider. MP has justified this recovery method on the grounds that low load factor customers require a higher proportion of capacity relative to energy usage.

This allocation ratio applies to the final revenue deficiency approved for recovery from the various rate classes and may not truly reflect the share of costs as noted in MP's cost study. As MP has argued that the demand credit is in lieu of paying for a new peaking plant, the rate design should reflect how the cost of a new peaking plant would have been allocated in MP's cost study in a rate case.

MP's workpapers from the recent (16-664) rate case show the following allocation factors applicable to "Demand Production:"[80]

SUMMARY

| ALLOCATION FACTOR RATIO TABLE EXTERNALLY DEVELOPED | ALLOC | TOTAL RETAIL (4) | RESIDENTIAL (5) | GENERAL SERVICE (6) | LARGE LIGHT & POWER (7) | LARGE POWER (8) | MUNICIPAL PUMPING (9) | LIGHTING (10) |
|---|---|---|---|---|---|---|---|---|
| DEMAND-PRODUCTION | | | | | | | | |
| 1 DEMAND PRODUCTION | DPROD | 0.843600 | 0.106550 | 0.066250 | 0.146040 | 0.520300 | 0.001930 | 0.002530 |
| 2 DEMAND PRODUCTION (FERC) | DPRODR | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 |
| 3 DEMAND PRODUCTION (RETAIL) | DPRODJ | 1.000000 | 0.126304 | 0.078532 | 0.173115 | 0.616761 | 0.002288 | 0.002999 |
| 4 DEMAND PRODUCTION - DIRECT TO GRE | DPRODLP | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 |

MP should distribute the Retail Recovery Target (84.360%) of $10.6 million (max.) according to the ratios indicated above. (The first row corresponding to "Demand Production.")

However, alternatively, as a second-preference, staff suggests that the Commission adopt Recovery Method 1 on grounds of simplicity of calculation.

### 3. CUB/Department Concern of Participant Manipulation

MP's response to PUC Information Request No. 8 elaborates on the calculation of the energy credit. This credit requires, first, the calculation of the difference between two load definitions:

- the higher of the average actual load that existed four hours before the curtailment was communicated, or
- the average of the load over four hours before curtailment actually took effect.

This can potentially be altered by the customer in light of MP's notice of curtailment.

The energy credit is given for the difference between this load and the actual load during curtailment period. This load, too, is under the control of the customers. However, this difference cannot exceed the Firm Service Level which, staff presumes, is set in the contract. Within this ceiling established by the Firm Service Level, staff believes CUB has identified a

[80] Docket No. 16-664, Compliance Schedule 16, Revised December 3, 2018, Page 42 of 46.

genuine potential for varying the load within four hour threshold to maximize receipt of the energy credit.

### *E. Compliance Reporting*

Fresh Energy and the OAG recommend that the Commission require MP to file quarterly reports, for similar reasons. Fresh Energy recommends MP report when MP called Product B, for how much capacity, and the market price avoided for each hour. The OAG recommends the reports show all of the times that MP interrupted customers, the energy market prices at the time, and the reasoning for its decision to curtail.

Staff agrees with the parties' underlying reasoning. Fresh Energy aims to "provide transparency and accountability," and the OAG's wants "close oversight," which are important components of monitoring impacts to ratepayers. At the same time, in staff's opinion, because it will take effort from the Company to put together a comprehensive report, and given that neither staff nor the Commission can realistically address the program every three months, quarterly reports may be excessive. Arguably, the frequency of the reporting should on some level reflect how the Commission is able to hold MP accountable or administer close oversight, and an annual filing with quarterly data might be more practical than quarterly reports.

As noted in the Parties Comments section of the briefing papers, the Department recommended filing an annual compliance report that would include several items, including, among other things, detailed information on the Firm Load Control periods and how customers responded to those events.

MP responded to the reporting requirements recommendations in reply comments, noting:

> while Minnesota Power is agreeable to the Department's recommendation to require an annual compliance filing with the information listed in its Initial Comments, it believes additional quarterly reporting as requested by some stakeholders is unnecessarily burdensome and the Company does not support that recommendation.[81]

Staff believes MP's response is reasonable.

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[81] MP reply comments, at 2.

## VI. Decision Options

**Entire Petition**

1. Approve MP's entire petition as filed. (MP, LPI, AMEA, Fresh Energy, industrial customers)
2. Reject MP's entire petition. (CUB, OAG)
3. Roll this matter into MP's next IRP filing.

(Staff note: For those who supported approving the entire petition, staff did not list those parties again in the individual product sections below.)

**Product A**

4. Approve Product A ($0.60 per kW of interruptible billing demand per month). (Department)
5. Deny Product A. (Staff note: There is no rate impact associated with Product A.)

**Product C**

6. Approve Product C. (Department)
7. Deny Product C.

**Product B**

8. Approve Product B as filed by MP.
9. Deny Product B (the costs of the proposed Product B outweigh the expected benefits). (Department, OAG, CUB)

If the Commission approves Product B:

**MP's position**:

10. Approve the demand credit of $7,000 per MW-month;
11. Approve the energy credit of $30 per MWh.
12. Approve an initial demand credit of $3,500 per MW-month (OAG);

**Modifications to Product B:**

13. Remove the four-hour minimum Firm Load Control duration. (Fresh Energy, AEMA)
14. Use a period of the previous five non-event business days to set a baseline for an economic DR program. (CUB, Department, AEMA, MP)
15. Allow customers to designate an MP-approved DR Aggregator. (AEMA)
16. Increase the subscription cap to 400 MW. (AEMA)
17. Establish an attainable baseline program goal for the participation level and increase the expected level of MW commitments annually. Start with 30 MW the first year, and 60 MW the second.
18. Create a penalty structure if Minnesota Power falls short of an agreed upon level of DR. (CUB)

**Recovery of Demand Credits for Product B:**

19. Approve MP allocation methodology Cost Recovery Method (CRM) 2 for the demand rebate, with a maximum rate of $0.000792/kWh for large power users, and a rate of $0.002126/kWh for all other customers. (MP CRM 2)
20. Approve MP's allocation methodology CRM 1 for the demand rebate, with a maximum flat rate of $0.001349/kWh for all firm customers. (MP CRM 1)
21. Approve the OAG allocation methodology for the demand rebate, with a maximum flat rate of $0.001123/kWh for all customers (firm and interruptible). (OAG)
22. Authorize an allocation methodology for the demand rebate both between wholesale and retail customers and among all firm and interruptible customer classes using the energy allocator form MP's last rate case. (DOC, response comments.)
23. Authorize an allocation methodology for the demand rebate based on allocation factors from MP's 2016 rate case that are applicable to "Demand Production." (PUC Staff Alternative)
24. Defer cost recovery until the next rate case.

**Product B Demand Credit Compliance Filing**

25. If the Commission adopts one of the demand credit recovery methodologies, then require MP to submit a compliance filing within 30 days that provides MP's calculation of the demand credits and all supporting calculations. (Staff)

**Recovery of Energy Credit**

26. Approve recovery of the $30/MWh Physical Interruptible Energy Credit through the FPE Rider. (MP)
27. Deny recovery of the Physical Interruptible Energy Credit through the FPE Rider, but allow recovery through a separate rider.[82] (Department)

**$5/MWh Adder for Buy-Through Events**

[82] Staff note: MP stated in its June 28, 2019 comments that "it is agreeable to the Department's suggestion to recover the Physical Interruptible Energy Credit through a separate rider."

28. The $5/MWh adder is considered to be an added incentive for participants of Product B not to buy through events, and should be returned to MP's customers via the same methodology used for recovery of the Physical Interruptible Energy Credit to offset some of the cost of the program. (Department)

**Department Reporting Requirements**

29. Direct MP to file an annual compliance report indicating:
    a. The number of Firm Load Control periods called by the Company;
    b. The number of hours per period;
    c. How many periods met the criteria to call a Firm Load Control but was not called, including an explanation of why each period was not called;
    d. How many customers responded to each event;
    e. The amount of curtailed energy;
    f. How many customers bought through each period;
    g. How many emergency events were called; and
    h. Customer response rates to each emergency DR request.

**OAG Reporting Requirements**

30. Require MP to report on Product B subscriptions in three months; solicit comments from interested parties on the level of subscriptions no later than 15 days from the date of MP's compliance filing.
31. Require MP to identify all the times that it interrupted, the prices at the time, and the reasoning for doing so. Also, MP must identify all times when energy market prices were higher than the $30/MWh interruptible credit and MP did not call an interruption, as well as MP's reasons for not calling an interruption.

**Fresh Energy Reporting Requirements**

32. Require MP to file quarterly reports on when it called Product B, for how much capacity, and the market price avoided for each hour.