April 25, 2019

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

RE: **Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E-015/M-18-735

Dear Mr. Wolf:

Attached are the Response Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Minnesota Power's (MP or the Company) Petition for Approval of an Industrial Demand Response Product in Minnesota.

The Application was filed on December 7, 2018 by:

Jennifer J. Peterson
Manager – Regulatory Affairs
Minnesota Power
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

The Department provides its revised recommendations herein.

Sincerely,

/s/ MICHAEL N. ZAJICEK
Rates Analyst

MNZ/ar
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E-015/M-18-735

I. BACKGROUND

On December 7, 2018, Minnesota Power (MP or the Company) submitted a *Petition for Approval of Minnesota Power's Industrial Demand Response Product* (Petition) to the Minnesota Public Utilities Commission (Commission), requesting approval of new Demand Response (DR) products and cost recovery.

On February 20, 2019, the Minnesota Department of Commerce (Department) and several other parties filed Comments responding to the Company's proposed DR products and cost recovery methodology. In its February 20, 2019 Comments, the Department recommended approval of the Company's proposed DR products but withheld making a final recommendation on cost recovery until response comments. The Department was generally concerned that the Company's proposed cost recovery mechanisms lacked proper support and that the recovery of costs would be better done though the Company's next rate case. The Department also requested that MP provide additional information in reply comments.

On March 13, 2019, the Company submitted reply comments responding to the Department and various other parties. In addition, other parties filed comments and reply comments.

II. DEPARTMENT'S RESPONSE TO COMMENTS

The Department responds to the following concerns in comments:

- concerns from several parties over whether the 150 MW of DR is actually necessary for the Company to obtain,
- a clarification of comparisons of Product A and Product B,
- a proposal by the Citizen's Utility Board (CUB) to limit participant manipulation,
- a proposal by Fresh Energy to remove the minimum period for Product B,
- a proposal by Advanced Energy Management Alliance's (AEMA) to allow demand aggregators to participate,
- the Office of the Attorney General's (OAG) proposal to require MP to include interruptible customers in cost recovery, and
- the Company's reply comments addressing the Department's Comments on the $5/MWh adder for the buy-though of events, the physical interruptible energy credit justification, recovery of the avoided capacity benefit payments, and the cost recovery methods.

A. NECESSITY OF DR PRODUCT

Several parties including the OAG and CUB expressed concerns about whether the 150 MW of proposed economic DR products were necessary for the Company to obtain. The Company stated in response to OAG Information Request No. 10 that 150 MW of industrial demand was included in the base case of its most recent Commission approved resource plan in Docket No. E015/RP-15-690 (2015 IRP). As DR resources are peaking resources, the Department took the inclusion of DR resources in the base case to indicate that the MP had a need for peaking resources.

However after reviewing the comments of other parties in this case, the Department further reviewed the 2015 IRP and notes the following:

- MP's 2015 IRP did not identify 150 MW of DR resources in the base case,
- Instead, MP included 150 MW of industrial DR in its base case in the Nemadji Trail Energy Center proceeding in Docket E015/AI-17-568 (NTEC), as an alteration to the Commission-approved 2015 IRP,
- The Department's Strategist models run in the 2015 IRP rarely identified any need for peaking resources for the Company.

In addition, in the NTEC proceeding:

- The Commission did not approve 150 MW of DR. The Commission stated in the NTEC proceeding that demand-response options must be better developed before a rider is approved to address concerns such as the fact that "LPI's proposal does not provide any assurance that customers would curtail their demand when needed, or explain how the cost of the program would be recovered." [1]
- Instead, the Commission ordered that the Company "continue to develop a demand-response rider and corresponding methodology for cost recovery in a new miscellaneous-docket filing."[2]
- 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.

This information impacts the analysis of the Company's proposed products because the capacity cost savings the Company uses to estimate the cost effectiveness of the proposed

[1] See Page 23 of the Commission's January 24, 2019 *ORDER APPROVING AFFILIATED INTEREST AGREEMENTS WITH CONDITIONS* in Docket No. E015/M/AI-17-568.
[2] *Id*.

product was based on the assumption that DR Product B would replace the need for the Company to obtain a Combustion Turbine unit for peaking purposes (as DR is a peaking resource). If a peaking resource is not needed, then there is no avoided capacity costs until the year in which such a resource is needed.

Thus, to calculate the value of the capacity component of a demand-resource resource, it would be more appropriate to look at the Midcontinent Independent System Operator's (MISO) Capacity Auction clearing price, as the price MP could sell this capacity into the market. The MISO Capacity Auction cleared at $10/MW-day in the 2018/2019 auction for MISO as a whole, but only $1/MW-day in MISO Zone 1, which includes all of Minnesota. Even at the higher MISO-wide result a MW of capacity would only cost $3,650 for an entire year, far lower than the over $7,000/MW-Month capacity value that the Company states would be gained by avoiding construction of a combustion turbine.[3]

Since no capacity need has been identified for peaking resources and the proposed cost of the resource exceeds its value, it does not appear that the Company's suggested capacity benefits would be gained by MP's customers. While it is still possible that this program could provide significant pollution abatement in the Company's high externality scenario, as the Department stated in its initial comments these benefits could be lost if participating customers buy through events or use self-generation resources.

Although the Department is generally supportive of demand response the benefits appear to be overstated. As a result of the above analysis, the Department does not recommend approval of the Company's proposed Product B at this time. However, if the Commission chooses to proceed with the Company's proposal, for example as a pilot project to assess the effects on emissions or other reasons, the Department offers further Comments below on other issues related to the Company's proposal and other parties responses.

B. COMPARING PRODUCTS A AND B

Several parties also stated concerns about the cost of capacity of Product B verses the rates currently in place for Product A.[4] The Department would like to clarify that comparison of the two products is not particularly useful as the products are vastly different. Product A pays for emergency-only interruptions to protect grid integrity, and is in fact only usable if called on by MISO in an emergency event. Product B meanwhile would be able to be called at any time (within proposed tariff limitations) for economic reasons by MP, most likely in response to a peak in energy demand. If MP were reaching a system peak and did not have additional resources the Company could not call on the Product A DR if MP could purchase energy in the

[3] See page 22-23 of the Company's initial filing.
[4] See the OAG's initial comments page 11 and CUB reply Comments page 2-3.

MISO Market. Product A is not so much an energy resource as a last-minute option called on by MISO to prevent the grid from collapsing.

The Department does not believe that the amount of Product A participation or the price affects whether the Commission should or should not approve Product B's implementation.

C. PROPOSAL TO LIMIT PARTICIPANT MANIPULATION

In its initial comments CUB raised a concern about Product B participants being able to manipulate the amount of incentive they gain by increasing their load during the period after they have received notice of an event but prior to the event beginning. CUB noted that the Company's proposed Product B would base the available energy for physical curtailment on 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." Essentially CUB was concerned that "by giving customers advance notification of an event and allowing those customers to take the average of four hours before interruption begins allows for time to manipulate their demand to increase the amount of curtailable load, increasing the incentive those customers can earn." CUB was also concerned that such a short period of time might not be representative of that customer's typical load. CUB recommended using a longer time period from non-event days to set an average firm load; specifically, CUB suggested a period of the previous five non-event business days.

In its March 13, 2019 reply comments AEMA supported CUB's recommendation and suggested using an adjusted high 4 of 5 days baseline.

The Department also agrees with CUB's recommendation. If the Commission chooses to approve the Company's proposed Product B then the Department recommends that the Commission adjust the product in a fashion similar to that which CUB or AEMA proposes.

D. PRODUCT B MINIMUM PERIOD

In its initial comments Fresh Energy recommended that Product B be modified to remove the minimum firm load control duration period of four hours so as to allow the Company more flexibility in calling events for the highest cost hours. Fresh Energy stated that the average price of the most expensive 1% of hours for MP was $113 per MWh in 2017, but only four days had consecutive four-hour periods with an average price above $110 per MWh.

In its March 13, 2019 reply comments LPI stated that it does not oppose Fresh Energy's proposal but notes that large power customers generally cannot rapidly ramp up and down production operations and thus the minimum notice periods and minimum duration limit the frequency and duration of interruptions are critical for customers to prepare the facilities and manage risk.

The Department agrees with Fresh Energy that shorter periods would allow MP to target the most expensive hours more flexibility; however, there are several concerns. As LPI's comments note some customers may not be able to respond well to a short interruption, which may lead to more participating 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.

E. AEMA AGGREGATION PROPOSAL

AEMA proposed that the Commission allow customers the option to designate an MP-approved demand response aggregator to manage participation of some or all customers to reduce risks for customers if a participating customer is unable to respond as expected. AEMA stated that demand-response aggregators would increase reliability and lower the overall costs of DR products.

In its March 13, 2019 reply comments MP did not support AEMA's proposal and instead stated that the Company's programs work best if they directly connect with the customers due to automation of systems. MP further stated that in Docket No. E999/CI-09-1449 the issue was discussed in depth and not approved. Finally, the Company stated its belief that a third party administrator in MP's service territory would impinge on the Company's service territory.

The Department notes that in Docket No. E999/CI-09-1449 the Commission prohibited "Aggregators of Consumption" (ARCs) from bidding demand response resources directly into the MISO wholesale energy and ancillary services market.[5] AEMA's proposal in this case is different since it involves delivery of DR interruptions directly to MP. If the demand response aggregator worked with the Company and did not bid the products directly into MISO then it would not be prohibited by the Commission's previous order.

The Department's position in Docket No. E999/CI-09-1449 was that if working with ARCs would expand participation or increase cost-effectiveness of DR resources, then it should be pursued. In this case AEMA's proposal could potentially improve Product B by allowing customers participating in Product B to respond more flexibly. However, it is not known how much AEMA's proposal would cost or how it would affect participation, given the profile of MP's customers. Thus the Department believes that AEMA's proposal potentially has merit, but

[5] See the May 18, 2010, *Order Prohibiting Bidding of Demand Response Into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities* in Docket No. E999/CI-09-1449.

should be explored further if the Commission chooses to approve the Company's Product B proposal.

F. OAG'S COST RECOVERY PROPOSAL

In its initial comments the OAG proposed that costs should be recovered from interruptible customers, as well as firm customers, as all customers benefit from the proposal, and that this approach would be consistent with how costs of a new power facility would be recovered if one were built.

In its March 13, 2019 reply comments MP clarified that only the portion of the load that interruptible customers had associated with Product B would be excluded from cost recovery and that the rest of the customer's firm load would have the costs of the Demand response products recovered from them.

While the basis for OAG's assertion that capacity costs of new a power facility would be charged to interruptible customers is unclear, MP has no capacity need for the foreseeable future, as discussed above. Therefore, the Department recommends that the Commission disallow MP's proposal to charge any ratepayers for the estimated $12.6 million for demand credits at this time. However, it may be reasonable for costs for Physical Interruption Credits paid for economic interruptions to be charged to all ratepayers, if the Commission chooses to approve Product B. This issue is discussed further below.

G. $5/MWH ADDER FOR THE BUY THROUGH OF EVENTS

In its February 20, 2019 Comments, the Department requested that the Company explain in reply comments whether the $5/MWh adder for customers that choose to buy through interruptions would be retained by the Company or returned to customers via the Fuel and Purchased Energy Adjustment.

In its March 13, 2019 reply comments MP stated that the $5/MWh 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. The Company estimated that the fixed cost recovery included in the firm energy rate is around $6.78/MWh. The Company also noted that in MP's next rate case the adder would become a revenue credit that would benefit customers.

The Department does not agree with the Company's proposal to keep the $5/MWh adder for shareholders. If the adder is considered to be an increased incentive for participants of Product B not to buy through 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. Therefore the Department recommends that, if the Commission approves the Company's Product B, all income from the $5/MWh adder should be returned MP's customers.

H. PHYSICAL INTERRUPTIBLE ENERGY CREDIT JUSTIFICATION

In its February 20, 2019 Comments the Department requested that MP provide further support for its proposal, including justification for any rule variance that may be required to allow use of the Rider for Fuel and Purchased Energy (FPE Rider) to recover the costs of the $30 per MWh Physical Interruptible Energy Credit. 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 most recent general rate case" and that this adjustment per kWh is calculated by subtracting the base electric cost (cost of fuel consumed in the generation of electricity and purchased power that is set in a rate case) per Kwh by the current period cost of energy purchased and fuel consumed per Kwh. The cost of energy purchased is defined as "the cost of purchased power and net interchange defined by the Minnesota uniform system of accounts, … account 555 and purchased under federally regulated wholesale rates for energy delivered through interstate facilities." There is no definition in these rules for costs of power not purchased.

In its March 13, 2019 reply comments MP stated that when customers physically curtail energy the Company 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 Company concluded by saying that this program is unique and that there is unlikely to be any precedent for recovery of these costs through the FPE Rider.

While the Department believes that it might make sense to recover these costs through the FPE Rider, the Company 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. As the costs the Company proposes to recover to not fit with Minnesota Rules, parts 7825.2390 through 7825.2920 and 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. Instead, a separate rider would be required, as discussed in the next section.

I. RECOVERY OF THE AVOIDED CAPACITY BENEFIT PAYMENTS

In it February 20, 2019 Comments the Department did not support MP's proposal to create a new rate rider for the capacity costs associated with demand response Product B and stated that recovery of such costs would be better suited for the Company's upcoming rate case.

In its March 13, 2019 reply comments MP stated that due to the unique scale and nature of its large industrial customers, a current cost recovery rider is the most appropriate method of cost recovery. MP further stated that a cost recovery rider was explicitly stated in both of the Commission's orders directing the Company to develop a demand response program. MP stated that the Company cannot implement a program for which the ability to recovery costs is uncertain.

The Department recognizes that due to the uncertainty as to the actual cost of DR Product B, the Company would prefer to recover the costs through a rider. As indicated above, MP has not supported its proposal to recover any capacity costs stemming from its proposal at this time. However, if the Commission approves the Company's product B, the Department concludes that the Commission should deny the Company's proposal to recover any capacity costs in the rider but allow the Company to recover costs of the Physical Interruptible Energy Credit in the rider. If the Commission chooses to approve the recovery of the Company's proposed capacity costs the Department maintains its position from direct that there is inadequate support for the recovery of these costs through a new rider, and that instead these costs should be recovery in the Company's next rate case.

J. COST RECOVERY METHODS

The Department provides its final recommendation on cost recovery methods. In initial comments, the Department stated:

> As an initial matter, the Company proposes to use the generation demand allocator for the DR program Avoided Capacity Benefit costs to allocate costs between wholesale and retail since the product is essentially serving as a replacement for new generation infrastructure. Since the proposed Product B is open to a maximum of 150 MW of participation, the maximum cost for implementing Product B is $12.6 million. The Department agrees with MP that the Company's approved generation demand allocator (D-01) from MP's 2016 rate case would be reasonable to use to allocate costs to retail customers. Using this allocator the Company would aim to recover up to $10.6 million from retail customers if Product B is fully subscribed. The Company then proposes two options for allocating the $10.6 million among the retail customers.

Given the analysis above indicating that MP has no capacity needs and the corresponding recommendation that the Commission deny recovery of the $12.6 million in capacity costs, the Department does not recommend use of the D-01 allocator to allocate costs between wholesale and retail customers.

Instead, if the Commission chooses to approve the proposed Product B, the Department recommends that the Commission require MP: 1) to 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) to 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.

III. RECOMMENDATIONS

The Department maintains the following recommendations from initial comments:

- approve the Company's proposed Product A;
- require the Company to include an analysis for updating the Product A credit per kW in an annual Compliance Filing each year for Commission approval; and
- approve the Company's proposed Product C.

Due to the analysis above of the necessity of peaking generation for the Company, the Department recommends the following regarding proposed Product B. Overall, the Commission should deny the Company's proposed Product B given that the costs of the proposed Product B outweigh the expected benefits. However, if the Commission chooses to approve the Company's Product B then the Department recommends that the Commission:

- require the Company to file an annual compliance report including at least the following information:
    - the number of Firm Load Control Periods the Company called,
    - the number of hours per period that the Company called,
    - how many periods met the criteria for the Company to call a Firm Load Control Period but a Firm Load Control Period was not called, and an explanation for why each period was not called,
    - how many customers responded to each event,
    - the amount of curtailed energy,
    - how many customers bought though each period,
    - how many emergency events were called,
    - customer response rates to each emergency DR request, and
    - any other data the Commission determines would be useful;
- modify the Product B in a fashion similar to that which CUB or AEMA proposes regarding the measurement of the baseline for the credit;
- include interruptible customers for the purposes of cost recovery if the Commission chooses to approve Product B;

- order that all income from the $5/MWh adder from Product B be returned MP's customers;
- deny recovery of the physical interruptible energy credit through the FPE Rider but allow recovery through the new rider, along with all revenue from the $5/MWh rider;
- deny recovery of any capacity costs in the rider; and
- require the Company to allocate costs of the rider both between wholesale and retail jurisdictions and among all firm and interruptible customer classes using the energy allocator from MP's last rate case.

/ar

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Response Comments

Docket No. E015/M-18-735

Dated this 25th day of April 2019

/s/Sharon Ferguson

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