State of Minnesota
Before the Public Utilities Commission

Dan Lipschultz	Commissioner
Matt Schuerger	Commissioner
John Tuma	Commissioner
Katie Sieben	Commissioner

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product

Docket No. E015/M-18-735

Initial Comments of the Citizens Utility Board of Minnesota

The Citizens Utility Board of Minnesota ("CUB") respectfully submits these comments regarding Minnesota Power's ("the Company") Petition for Approval of an Industrial Demand Response product. CUB is focused on Product B in these comments and does not offer an opinion on Product A due to Product A's similarity to their current demand response offering.

Demand response (DR) is an important resource that should be utilized to respond to characteristics of the electricity system such as the need to meet supply and demand for electricity in real time, the rapid changes that can occur on the grid, and reduce the need for capital-intensive system investments. CUB is in favor of DR that saves customers money, reduces emissions, and increases the reliability of the grid. While reviewing new DR proposals, CUB looks for programs that meet those criteria while ensuring an equitable cost allocation for the program.

CUB supports DR programs that are cost-effective and translate savings to all customers. If the cost to save energy is lower than the cost to generate energy, customers will see benefit from DR and energy efficiency programs. Benefits from DR programs are differentiated between participating customers and non-participating customers. Customers participating in DR products receive direct benefits such as savings on their bills and incentive payments from the utility. If requesting funds from non-participating customer classes, the program must provide enough benefits to support the need for those customer classes to incur those costs. DR provides system-wide benefits for non-participating customers in a couple different ways. In the short run, customers see a lower bills from reduced variable costs such as fuel charges during curtailment. In the long run, peak reduction from DR programs offer benefits by avoiding or deferring investments in additional generation, transmission, and distribution capacity from the utility. For non-participating customers to see the benefits from DR, the program must be used, and the resources must be available when called upon. The utility must show that customers receive these positive customer benefits. This is demonstrated by a reduction on bills through reduced costs.

Environmental benefits from DR include the reduction of emissions by shifting demand away from peak times and by allowing the integration of renewable energy. Limiting demand during peak hours typically displaces generation resources which produce greater emissions than during other periods of the day. DR can also help manage the variable nature of renewable energy by deploying more quickly than generation resources are able to.

DR provides reliability benefits to customers as well by reducing demand for electricity during times of a shortage. DR can help limit the strain on the system during these times and reduce costly outages.

DR can be categorized into either load response or price-based. Load response relies on customer incentives in order to induce a reduction in load. Price-based programs include tariffs that allow customers to make decisions on electricity use in response to economic signals from the utility. An example from Illinois shows that real-time pricing would have saved the average Commonwealth Edison customer $86.63 annually in comparison to a traditional flat rate system.[1] Real-time pricing incentivizes the customer to change their behaviors in response to price signals which would lead to a more efficient pricing system. This also gives customers greater control and a more natural interaction with the energy system which not only leads to personal monetary savings but also to the systemwide benefits listed above.

CUB is concerned about several aspects of the proposal. For example, the proposal for Product B is a load response program that relies on large industrials curtailing load in response to a utility load control event in return for incentives. Load response programs rely on incentives that can lead to inefficient outcomes if the incentive structure is not designed correctly. If the program does not get used to its full capability, or participants are buying through the curtailment periods, the key customer benefits will go unrealized and customer funds will be wasted. CUB believes Minnesota Power's proposal falls short of an effective DR program for these reasons:

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

I. Customer Benefits

Customers see benefits from DR programs when the Company calls an event that curtails energy at a cheaper price than it would cost to generate the energy or purchase that energy from the market. Customers also see benefit in the form of avoided capacity and avoided emissions. But any new resource must demonstrate that they are the least cost option for customers.

Minnesota Power lists the value of avoided energy over the ten year span of the product as $10 million and the value of avoided capacity as $4.6 million. Combined, Minnesota Power cites customer benefits at about $15 million over 10 years.[2] These savings assume Minnesota Power is going to call the maximum requested firm load control events of 600 hours or 90,000 MWh each year for the next ten years in order to realize the $10 million of savings from avoided energy costs. CUB is concerned with the costs to non-participant customers for this program where they will see little benefit.

If Minnesota Power uses the program to its full extent by calling 90,000 MWh of curtailment each year, non-industrial customers would see very little benefit from this program. Minnesota Power projects the cost of

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[1] Jeff Zethmayr and David Kolata, *The Costs and Benefits of Real-Time Pricing: An empirical investigation into consumer bills using hourly energy data and prices,* (November 2017), at 3. Avalailable at: https://citizensutilityboard.org/wpcontent/uploads/2017/11/20171114_FinalRealTimePricingWhitepaper.pdf

[2] Petition for Approval of Minnesota Power's Industrial Demand Response Product, Docket No. E-015/M-18-735, p. 22.

peaking energy to be $41/MWh over the next 10 years.[3] If Product B is fully subscribed and 90,000 MWh of energy is curtailed each year, non-industrial customers are still paying the full cost of that peaking energy through the Physical Interruptible Credit paid to participating industrial customers and the $10.6 million projected to be recovered from customers. Minnesota Power proposes a $30/MWh Physical Interruptible Credit and rightly state that this is lower than the projected $41/MWh peaking energy cost over that timeframe. But retail customers are still on the hook for $10.6 million to support the Demand Credit for Product B over ten years. This means customers are paying $1.06 million for the program each year. Assuming the full 90,000 MWh is called each year, assuming no customer buy-throughs, and assuming the proposed Demand Credit is collected on a fixed basis over ten years, using simple math, this works out to:

$1,060,000 / 90,000 MWhs = $11.78 per MWh

$11.78 + $30 per MWh physical interruptible credit = $41.78 per MWh

By adding the costs for the Physical Interruptible Credit and the amount to be collected through the DR, customers are still on the hook for the full $41/MWh cited by Minnesota Power as the cost of peaking energy over the next ten years if the program is used to its full extent.

The scenario above assumes full participation in the program. A more likely scenario is that participating customers will buy-through a portion of the events or the Company may not call the full 90,000 MWhs in a year. In that case, customer costs will be spread over a smaller number of MWh curtailed which reduces the actual benefits customers see even further. For example, if there is a mild winter or mild summer that limits the energy curtailed to 45,000 MWh in a year, customers will then be paying $53.56/MWh as they will be paying the $30 physical interruptible credit to customers and the annual $1.06 million charge through the DR rider, shown below:

$1,060,000 / 45,000 MWh = $23.56 per MWh

$23.56 + $30 per MWh physical interruptible credit = $53.56 per MWh

$53.56 per MWh * 45,000 MWh = $2,410,200

Customers would be better off paying the cost of peaking energy of $41/MWh at this rate, shown below:

$41 per MWh credit * 45,000 MWhs = $1,845,000

$2,410,200 - $1,845,000 = $565,200

Customers would be paying $565,200 more through this program throughout the year under this scenario. The $41/MWh charge is levelized over ten years. Annual energy cost savings range from $37.56 in 2019 to $49.50 in 2028.[4] If Product B does not get utilized to its full potential in earlier years, the cost of the program will be significantly higher than its benefits and the Company will be unable to make up that shortage in later years as they will be unable to call more DR than the 600 hours of Firm Load Control that would be contracted with industrial customers. Minnesota Power also does not have a required minimum number of

[3] Petition for Approval of Minnesota Power's Industrial Demand Response Product, Docket No. E-015/M-18-735, p. 21.

[4] Office of the Attorney General Request for Information 7, Docket No. E-015/M-18-735

Firm Load Control hours or events for Product B that would prevent this product from being underutilized and would ensure customers are seeing benefits in return for their costs.[5]

Furthermore, the proposed incentive structure allows for a massive reallocation of ratepayer costs onto non-industrial customer classes for very little benefit. If energy is curtailed, this allows participating industrial customers to "triple dip" in benefits. First, industrial customers receive a Demand Credit for Product B of $7,000/MW-Month which is only slightly less than the cost of construction for new peaking assets such as a combustion turbine.[6] Second, when a curtailment event is called, customers participating in Product B will receive the $30/MWh Physical Interruptible Credit. When the Demand Credit and Physical Interruptible Credit are combined, this represents an extremely high incentive for industrial customers to participate in DR. What makes DR attractive for utilities is its significant cost savings over traditional generation. At full use, this program represents minimal benefits for non-participating ratepayers at best. If the program is not used to its full capacity on annual basis, which seems very likely, this program pencils out to a net cost for non-participating ratepayers.

On top of the direct costs non-participating customers are paying to participating customers, industrial customers also receive a benefit in the form of the avoided cost of energy while curtailing their operations. In Minnesota Power's service territory, industrial customers account for a majority of the load and will therefore see greater benefit from a reduction in utility fuel costs when compared to non-industrial customers. This results in a windfall for industrial customers with little benefit for other customer classes.

CUB also questions the avoided capacity benefits cited by the Company as a result of this program. Minnesota Power's most recent resource plan did not identify any need for peaking resources other than 150 MW of industrial demand response.[7] The lack of need for any additional peaking resources puts into question the need for this program to avoid additional capacity investments throughout the program. Even though Product B is cost competitive with a new CT power plant, if there is no need for new peaking resources, this program is not avoiding any new capacity and completely negates the cited $4.6 million avoided capacity benefit. Based on CUB's calculations, the cost seems to pencil out to customers paying for the cost of a new power plant through this DR program with customer money all funneling to participating industrial customers.

CUB believes the overall benefits for non-industrial customers are unclear at best and negative at worst. Minnesota Power has provided system wide costs and benefits but has not clarified how individual customer classes will benefit from this program in order to justify placing costs on those customers. Minnesota Power needs to provide a cost-benefit analysis by customer class for this program.

By providing these analyses, stakeholders and customers will have a clearer picture of what they are gaining out of this program. Further, the Company should be required to provide these analyses on an annual basis to prove there are ongoing positive customer benefits from this program. Because positive customer benefits from this program are reliant on full annual utilization of this program, and even then it is in doubt, CUB believes customers should not be paying the costs for this program and if it goes underused with Minnesota Power paying a penalty if this is the case.

[5] Citizens Utility Board Request for Information 3, Docket No. E-015/M-18-735
[6] Citizens Utility Board Request for Information 5, Docket No. E-015/M-18-735
[7] Office of the Attorney General Request for Information 10, Docket No. E-015/M-18-735

II. Event Utilization

One of the major benefits of DR is avoided capacity due to a reduction in peak demand which limits or defers the need for additional generation, transmission, and distribution capacity. The cited avoided capacity benefit from this proposal is listed at $4.6 million. But, for customers to realize an avoided capacity benefit, the DR product must be available when called and able to perform reliably as a resource.

The Company currently has an industrial emergency capacity DR product. Because this product is an emergency capacity only product, it is not directly comparable to Product B in this petition. While it is not directly comparable, Minnesota Power had not called on participating customers to reduce load from 2014-2018.[8] While Minnesota Power has offered a DR product to industrial customers, the Company has very little experience calling on industrial customers to reduce load. It can also be expected that customers will buy-through a percentage of events. 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.

CUB is skeptical that Minnesota Power can ramp up their actual DR curtailment from 0 hours of events to 600 hours of events in year one of the program. Because they are unable to call more than 600 hours of DR each year through this product, the Company will not be able to make up for a shortage in years down the line. As shown above, the economics of the program are reliant on the Company calling the 90,000 MWhs in a year.

By requesting funds from customers to support this program, the Company is promising customers will see benefits from avoided energy costs in the form of lower fuel costs and avoided capacity benefits. If this program is underutilized, customers will not see a reduction on their bills and there will be no verifiable avoided capacity benefit. To prevent the reality of the difficulty of ramping up a DR program from 0 MW to 150 MW, this program could be modified to limit customer risk and ensure the capacity is needed. One option is ramping up the program annually to allow for greater flexibility year over year.

Under this scenario, Minnesota Power could commit 30 MW in year one, 60 MW in year two and so on. In order to access additional DR, Minnesota Power must provide annual reporting showing the program was used and customers benefited from the program. This ensures a smoother transition from very limited DR to a reliable DR program. This method provides benefit for both the utility and customers. This would benefit customers by limiting customer costs for the program in the initial years to ensure this program is reliable and can endure and grow over time while still providing benefits. This benefits the Company by spreading customer acquisition costs for the program across multiple years and allows them to learn best practices before expanding to a greater portion of their resource offerings in later years.

This also allows Minnesota Power and the Commission to respond to demand growth by choosing the correct level of DR for the next year. Once Minnesota Power has proven that this program is used and provides customer benefit, the Company and stakeholders can determine the correct level of DR for customers in the next Integrated Resource Planning process. This would allow all parties to review what the most efficient and cost-effective level of DR is while reviewing all available resources.

[8] Minnesota Department of Commerce Request for Information 1, Docket No. E-015/M-18-735

III. Limit Participant Manipulation

CUB is also concerned about the Company's ability to develop a mechanism that results in a correct expected available energy for curtailment. Calculating the expected energy available for curtailment during an event can be difficult to determine and must be protected against participants increasing demand before an event in order to earn a greater incentive for curtailing. Minnesota Power is basing 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."[9]

This is concerning for two reasons. First, a shorter timeframe on the day of an event may not accurately represent the available energy for physical curtailment. A shorter timeframe to set average load for a participating customer allows for a much higher variation in load that may not be a true representation of that customers typical load. Event days may also allow for other factors such as weather to impact the level of curtailable load. Second, 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. These realities could lead to an incorrect estimation of the load available for curtailment.

This would lead to inefficiencies in the DR program. By ramping up usage right before an event, participants would not be providing an accurate representation of the impact their load has on the system, limiting the benefits a DR program has on the system and increases costs for customers by raising the total Physical Interruptible Credit paid to participating customers.

CUB recommends using a longer time period from non-event days in order to set an average firm load. EnerNOC, recommends a period of the previous five non-event business days to set a baseline for an economic DR program.[10] The average firm load from the previous five non-event business days more accurately captures average firm load available for curtailment by providing a more reliable load profile of participating customers and provides a better representation of the total impact that customer will have on the system by curtailing load. This also limits the ability for customers to manipulate the system by not giving them advance notice of an event.

IV. Conclusion

CUB recognizes that for industrial customers to participate in a DR event, they need a substantial enough incentive from the Company to consider interrupting their operations. But, this incentive must also represent the least cost resource.

The number one goal of any DR program is to save customers money in both the short run on customer bills through a reduction in variable customer costs and in the long run by avoiding utility investments. Product B provided in this petition fails to save non-participating customers money in either the short run or the long run and in fact represents a reallocation of costs from participating industrial customers who represent a majority of load in Minnesota Power's service territory onto non-residential customers for very little benefits for those customers.

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[9] Petition for Approval of Minnesota Power's Industrial Demand Response Product, Docket No. E-015/M-18-735, p. 18.

[10] EnerNOC, *The Demand Response Baseline,* (2009), at 6. Available at: https://www.naesb.org/pdf4/dsmee_group3_100809w3.pdf

Through Product B, customers will be paying the equivalent cost of peaking generation in a DR program without any evidence that this program will be avoiding or deferring investments in new capacity. This program also lacks consumer safeguards that protect their investment in a resource that has no assurances it will actually be used. If this program is not used to its full capacity on a yearly basis, customer benefits will fall drastically while costs per MWh curtailed will increase above the projected cost of peaking energy over the period of the program. The program design adds further doubts from CUB into the ability of this program to save customers money because it allows for the potential from participating customers to manipulate the system to earn a greater incentive. These concerns need to be addressed.

Before moving forward on a DR product that requires cost recovery from non-participating customers, Minnesota Power should provide:

- Cost-benefit analysis that provide greater assurances that customers are seeing an appropriate level of benefits in return for an increase in their electricity costs
- A more robust mechanism to determine available energy for physical curtailment to reduce the potential for program manipulation
- A discussion on the ability to ramp up the DR program annually to ensure appropriate use of customer funds and maximization of customer benefits
- Create a penalty structure if Minnesota Power falls short of an agreed upon level of DR

Respectfully submitted, February 20, 2019

/s/ Ben Bratrud
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CITIZENS UTILITY BOARD OF MINNESOTA
Information Request

Date of Request: January 2, 2019

Requested By: Joseph Pereira
josephp@cubminnesota.org

Requested From: Minnesota Power

Request Due: January 12, 2018

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product **Docket No. E015/M-18-735**

REQUEST:

1. Has the Public Utilities Commission ordered Minnesota Power to achieve a minimum level of demand response annually? If so, could Minnesota Power please provide the reference information to the docket number, document type, received date, and page this information can be found on.

RESPONSE:

Minnesota Power's last Integrated Resource Plan (Docket E-015/RP-15-690) was approved on July 18, 2016. The Commission's July 18, 2016 Order did not explicitly address Demand Response (DR) or provide reference to a minimum level of DR to be achieved annually. Minnesota Power's approach to DR is discussed beginning on Page 20 within Section III, and continuing on page 65 of Appendix B of the 2015 IRP.

In Minnesota Power's last general rate case (Docket E-015/GR-16-664), the Commission issued its final Order on March 12, 2018 that referenced DR. From that Order, Order Point 72 on page 115 states:

> "The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The record to support the submission to the Commission may be developed in either Docket E015/AI-17-568 - OAH Docket 68-2500-

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Response by: Jennifer J Peterson
Title: Manager – Regulatory Affairs
Department: Regulatory Affairs
Email Address: jjpeterson@mnpower.com
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> 34672 or a new miscellaneous docket. In the event the Company, LPI, and other stakeholders elect to proceed with a new miscellaneous docket filing, such filing shall be submitted for Commission approval within six months after the date of the final written order in this proceeding."

DR was also addressed in the Nemadji Trail Energy Center (NTEC) proceeding and Minnesota Power expects the forthcoming order in Docket No. E015/AI-17-568 to reinforce the rate case order and direct the Company to submit a DR product in a miscellaneous docket.

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CITIZENS UTILITY BOARD OF MINNESOTA
Information Request

Date of Request: January 2, 2019

Requested By: Joseph Pereira
josephp@cubminnesota.org

Requested From: Minnesota Power

Request Due: January 12, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product

Docket No. E015/M-18-735

REQUEST:

1. Does the contract between Minnesota Power and the participating customers of the proposed Demand Response Product B require a minimum number of events annually? If so, could Minnesota Power please provide information on the following conditions for Large Power Demand Response Product B:
    a. Minimum number of annual Firm Load Control hours
    b. Minimum number of annual Firm Load Control events

RESPONSE:

1. The contract between Minnesota Power and participating customers would not require a minimum number of annual Firm Load Control hours or events.

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Department: Customer Experience
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Citizens Utility Board of Minnesota
Information Request

Date of Request:	January 2, 2019
Requested By:	Joseph Pereira josephp@cubminnesota.org
Requested From:	Minnesota Power
Request Due:	January 12, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product **Docket No. E015/M-18-735**

1. Minnesota Power lists two key benefits realized by customers and society through demand response programs; 1) the $30/MWh physical interruptible credit is lower cost than dispatching peaking generation, and 2) customers benefit from avoided externalities.

   Minnesota Power projects the cost of peaking energy to be $41/MWh over the commitment period of their proposed program which works out to savings of $11/MWh of curtailed energy or about $1 million per year.

   a) Is Minnesota Power projecting linear savings of $11 for each MWh of energy curtailed or is the estimate an annual average assuming the maximum number of annual Firm Load Control hours of 600 hours?
   b) Could Minnesota Power please provide a walkthrough of the analysis and the assumptions used to determine a savings of $1 million per year.

RESPONSE

a) The energy costs ($41/MWh peaking energy cost and $11/MWh energy cost savings) mentioned above represent levelized values over the 10 year life of Product B. The annual savings are expected to be lower in the earlier years and increasing over the 10 year life of Product B. The annual savings increase over the 10 year life due to increasing peaking energy cost driven by rising natural gas prices.

b) Minnesota Power provided a TRADE SECRET workbook in response to Fresh Energy IR No. 1 that contains the analysis used to support both the annual and levelized energy cost and savings

Response by: Eric Palmer
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values referenced above. A non-disclosure agreement (NDA) is required to access the data contained in the TRADE SECRET workbook. Parties who have signed a NDA should refer to that workbook – in particular – tab “Energy” to view the analysis results. Minnesota Power developed an energy-only cost for a peaking resource based on the operating characteristics of a new GE 7FA.05 Combustion Turbine (CT). The energy-only cost took into consideration expected fuel prices, variable O&M (operations and maintenance) expenses, major maintenance expenses and avoided transmission losses. The annual costs were then compared to the “Contract Energy Curtailment Price”. The delta between the CT energy-only cost and the Contract Energy Curtailment Price is the annual customer savings. Assuming that all 90,000 MWh of Product B are used annually, the yearly customer savings vary from about $680,000 the first year up to about $1.7 million in year ten.

Response by:	Eric Palmer
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Citizens Utility Board of Minnesota
Information Request

Date of Request: January 2, 2019

Requested By: Joseph Pereira
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Requested From: Minnesota Power

Request Due: January 12, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product

Docket No. E015/M-18-735

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1. Minnesota Power proposes a demand credit for Product B of $7,000/MW-Month which will cost customers $12.6 million over 10 years, with Minnesota Power proposing $10.6 million to be recovered from retail customers. Minnesota Power projects approximately $4.6 million of avoided investment over 10 years due to this program.

    a. Could Minnesota Power please provide a walkthrough of the analysis and the assumptions used to determine a savings of $4.6 million of avoided investment over 10 years.
    b. Could Minnesota Power please provide a walkthrough of the analysis and the assumptions used to determine the $7,000/MW-Month proposed demand credit for Product B.

RESPONSE

a) Minnesota Power provided a TRADE SECRET workbook in response to Fresh Energy IR No. 1 that contains the analysis used to support the capacity savings values referenced above. A non-disclosure agreement (NDA) is required to access the data contained in the TRADE SECRET workbook. Parties who have signed a NDA should refer to that workbook – in particular – tab "Capacity" for the analysis results. The estimated $4.6 million in savings was calculated as the difference between the projected levelized revenue requirements for a new combustion turbine minus the capacity credit under Product B over the life of Product B. Please see cell B8 for the calculation.

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b) Minnesota Power negotiated the value of capacity purchased under the framework for Product B to ensure it provided benefit to all customers and to participants of Product B. The value of capacity must properly compensate customers signed up for Product B for the energy curtailment risk they are taking on by participating. The value must also provide a net benefit to customers who pay and receive the capacity, energy and avoided emission benefits from Product B. The $7,000/MW-month value was agreeable to Minnesota Power's Large Industrial Customers. Furthermore, customers are receiving a peaking-like generation resource at a price slightly lower than to construct new large generation assets like a combustion turbine.

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Citizens Utility Board of Minnesota
Information Request

Date of Request: February 1, 2019

Requested By: Joseph Pereira
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Requested From: Minnesota Power

Request Due: February 11, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product **Docket No. E015/M-18-735**

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1. Please explain the current accounting treatment for Product A and provide the reference to where this information can be found in Minnesota Power's most recent rate case.

RESPONSE:

In Minnesota Power's current rate case, Product A is considered to be Large Power revenue, and is accounted for as a reduction to Large Power revenue received. This can be seen in individual Large Power customer breakdowns provided in Minnesota Power's December 3, 2018 Compliance Filing, revised Compliance Schedule 10 in Docket No. E015/GR-16-664. Please refer to pages 36-37, 40-41, 46-47, and lines titled "RIS Discount (kW)" and "Fixed Price Interruptible Discount".

Response by: Mike Donahue
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Citizens Utility Board of Minnesota Information Request

Date of Request: February 1, 2019

Requested By: Joseph Pereira
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Requested From: Minnesota Power

Request Due: February 11, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product **Docket No. E015/M-18-735**

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1. Please provide the number of Firm Load Control periods Minnesota Power would have called as well as the number of MWhs that would have been curtailed on a monthly basis for the past 5 years had Product B been in place.
2. Please provide the estimated number of Firm Load Control periods Minnesota Power expects to call well as the expected number of MWhs curtailed on a monthly basis over the next five years.

RESPONSE:

1. Below are two table summarizing the Firm Load Control periods (Table 1) that could have called by Minnesota Power over the past five years and the associated industrial energy that might have been curtailed by customers (Table 2).

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Table 1: Firm Load Control Periods (Hours)

Month	2014	2015	2016	2017	2018
1	189	45	26	61	91
2	143	111	0	0	4
3	35	25	0	46	0
4	23	12	0	30	37
5	89	43	5	34	69
6	35	50	66	58	32
7	4	112	114	126	50
8	4	147	179	56	78
9	0	52	37	25	36
10	52	0	73	46	74
11	16	0	14	64	100
12	5	0	86	49	28
Total	**595**	**597**	**600**	**595**	**599**

Table 2: Potential Energy Curtailments by Industrial Customers

Month	2014	2015	2016	2017	2018
1	28,350	6,750	3,900	9,150	13,650
2	21,450	16,650	0	0	600
3	5,250	3,750	0	6,900	0
4	3,450	1,800	0	4,500	5,550
5	13,350	6,450	750	5,100	10,350
6	5,250	7,500	9,900	8,700	4,800
7	600	16,800	17,100	18,900	7,500
8	600	22,050	26,850	8,400	11,700
9	0	7,800	5,550	3,750	5,400
10	7,800	0	10,950	6,900	11,100
11	2,400	0	2,100	9,600	15,000
12	750	0	12,900	7,350	4,200
Total	**89,250**	**89,550**	**90,000**	**89,250**	**89,850**

2. For the next five years Minnesota Power expects the Firm Load Control periods and associated potential MWhs curtailed will be similar to the historical shown in the tables above. Where the Firm Load Control Periods will likely be concentrated during the peak winter and summer months.

   The proposed Industrial Demand Response product is flexible on when the Firm Load Control Periods can be called. Giving Minnesota Power the capability to adjust when the Firm Load Controls periods are called to align with the changing market dynamics due to the evolving power supply and customer

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usage patterns. Minnesota Power will manage this proposed demand response product to maximize the value of the energy curtailments for customers.

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