STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

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In the Matter of a Commission Inquiry into Standby Service Tariffs	**MINNESOTA SOLAR ENERGY INDUSTRIES ASSOCIATION'S COMMENTS ON XCEL ENERGY'S CREDIT MODIFICATION**
February 18, 2019	**Docket No. E999/CI-15-115**

COMMENTS OF THE MINNESOTA SOLAR ENERGY INDUSTRIES ASSOCIATION

I. BACKGROUND

On October 3, 2017 the Minnesota Public Utilities Commission (the Commission) published an order, which required Xcel Energy (Xcel) to file an additional proposal for its solar PV capacity credit after discussing with stakeholders.[1]

On November 2, 2017 Xcel Energy filed a compliance filing consistent with that order. In its filing, Xcel highlighted an agreement that was reached with the Minnesota Department of Commerce (the Department of "DOC") and MnSEIA. Other stakeholders, like MetCouncil, the City of Minneapolis and Target were solicited for their input prior to the filing and in regards to the agreed upon terms of the arrangement. In short, the parties agreed to modify Xcel's rate to use an updated $4.52/kW-month as the predicate for the conversion into a per-kWh pricing schema and to include a term-period for impacted customers that extended until 2024. This modification would serve as an interim rate while Xcel would do as follows:

[1] *See* ORDER APPROVING THREE TARIFFS WITH CONDITIONS AND REQUIRING XCEL TO FILE A PROPOSAL FOR ITS SOLAR PV CAPACITY CREDIT RIDER, MINNESOTA PUBLIC UTILITIES COMMISSION, Docket No. E-999/CI-15-115, Doc. Id. 201710-136061-01 (Oct. 3, 2017).

Require Xcel, following discussions with the Department of Commerce, MNSEIA and other interested parties, to file a proposed methodology for determining the appropriate solar capacity or demand credit. The methodology should consider reasonable ways to incorporate cost of service principles in demand charges for behind-the-meter solar customer accounts as well as also address the additional issues surrounding the solar capacity or demand credit rider as raised by parties in this docket. Xcel should file its proposal and discussion of the additional issues by September 19, 2018 as well as rationales for why this study is or is not a better indicator of capacity or demand value than previously derived values. Parties will be allowed 60 days to respond.

As part of this process, Xcel, with input from the Department, MNSEIA and other interested parties, will evaluate to what extent the billing demand quantities of customers with solar generation is affected by their solar production. Xcel will review whether there is a mismatch between the net billing demand of individual customers with solar installations and their net demand on system peak demand days relative to non-solar generation customers and, if so, how to reflect that difference appropriately in demand billing or comparable rate component. Xcel will also be conducting a new ELCC load study in preparations for its resource planning process. In addition, Xcel will compare this credit to current peak controlled demand credits.[2]

On June 5, 2018, Xcel invited some stakeholders to a meeting to develop the scope and methodology of a study of billed demand at individual customer sites with PV.

On August 17, 2018, Xcel published its initial study results.[3]

On August 28, 2018, Xcel hosted a follow-up meeting with MnSEIA and the Department.

On October 19, 2018 Xcel published its PV Demand Credit Rider Methodology. This was the first time stakeholders had a chance to view the impacts that Xcel's study results would have on the credit valuation.[4]

On October 26, 2018, the Commission posted its notice of comment period, requesting commentary on Xcel's methodology and credit valuation.[5]

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[2] *See* STANDYBY SERVICE TARIFFS, XCEL ENERGY, Docket No. E-999/CI-15-115, Doc. Id. 201711-137143-01 at 3 (Nov. 2, 2017).

[3] *See* STUDIES COMPLIANCE, XCEL ENERGY, Docket No. E-999/CI-15-115, Doc. Id. 20188-145852-01 (Aug. 17, 2018).

[4] *See* PV DEMAND CREDIT RIDER METHODOLOGY, Docket No. E-999/CI-15-115, Doc. Id. 201810-147188-01 (Oct. 19, 2018).

[5] *See* NOTICE OF COMMENT PERIOD, MINNESOTA PUBLIC UTILITIES COMMISSION, Docket No. E-999/CI-15-115, Doc. Id. 201810-147312-01 (Oct. 26, 2018).

II. COMMENTS

i. MNSEIA DOES NOT BELIEVE XCEL COMPLIED WITH THE PURPOSE AND INTENTION OF THE RESTUDY PERIOD AND CONTENDS THE COMMISSION MAY WANT TO REQUIRE XCEL TO RECALCULATE THE CREDIT BASED UPON THE NOVEMBER 2, 2018 AGREEMENT.

Xcel's calculations reflect a different approach to the calculation of the PV demand credit than what MnSEIA understood the agreement to represent. Our understanding of the reason for the restudy process was because Xcel was unable to count PV Capacity, generated by commercial and industrial solar customers, towards MISO accreditation. Instead, the Department and Xcel contended that, while the capacity accreditation may result in a $0 valuation, commercial and industrial solar customers were being over billed on their demand changes because of an inability to capture the general demand reduction associated with day-time solar use.

While MnSEIA does not agree that the MISO accreditation issue requires a devaluation of the initial $5.15/kW-month Capacity Credit – we believe very strongly that daytime solar use benefits the utility and its ratepayers even if it is difficult to calculate the actual value - our members did want to explore an alternative way to calculate a compensation method for customers that might result in a permanent methodology. Business certainty is a valuable commodity, and whether solar customers receive a credit for their capacity provided or see a comparable bill savings due to lower demand changes is largely immaterial to making a sale.

However, after seeing Xcel's approach to calculating what we believed was intended to be a bill credit savings associated with a demand charge reduction, MnSEIA was surprised to see that Xcel's methodology looks very similar to the original Capacity Credit calculation. Xcel's general formula is an attempt to evaluate the benefits from capacity provided by C&I solar customers during the utility's peak periods. The only real look at individual customer data is an attempt to reduce the credit's valuation by highlighting that some of the crediting takes place as a demand charge reduction.[6] So, in short, Xcel appears to have taken the previous Capacity Credit methodology and just reduced it.

While MnSEIA is content to argue the merits of this new Capacity Credit formulation, and we will do so below, the outcome of this study process did run counter to our expectations that this was going to be a customer-focused credit that mitigates an inherent overbilling from

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[6] *See* PV DEMAND CREDIT RIDER METHODOLOGY, Docket No. E-999/CI-15-115, Doc. Id. 201810-147188-01 at 4, Table 2 (Oct. 19, 2018); *See also* RESPONSES TO MPUCE IRS 1-3, XCEL ENERGY, Docket No. E-999/CI-15-115, Doc. Id. 20179-135377-01 at 3 (Sept. 11, 2017).

demand charges that are measured at the customer's non-coincident peaks, not at the time of the coincident system peak.

One option for the Commission is to require Xcel to restudy the PV Demand Credit Rider methodology and focus on where C&I solar customers are overbilled on their demand charges. If the Commission does wish to go this way, MnSEIA requests that the November 2, 2017 negotiated agreement be modified to account for this lost year due to Xcel's misapplication of the study. We suggest changing the 2024 end date to 2025. This restudy period could be couched within a rate case or independent investigation.

There are other reasons to go this direction. Most importantly, line "j" of Xcel's Table 2 highlights a Reduced Billed Demand Value of $0.41.[7] This number was developed with data from just the 24 pre-existing solar customers under this program. There are now many more projects that have applied for or are built out under this program.[8] Using only a fraction of the projects is not great science, may not be representative, and may yield an artificially high reduction amount.[9] Furthermore, those 24 projects came online under a very different tariff structure and at a very different time. For instance, prior to the transition to a PV Demand Credit Rider, customers 1) were required to be on standby service; 2) had systems greater than 100kW as opposed to 40kW; 3) may have built their systems for sustainability benchmarks as opposed to actual efficient usage; and 4) may have used modules that no longer exist or are not efficient by today's standards. In short, the stakeholders will have a more robust data set for determining some of the variables within the methodology, if we take an opportunity to restudy data from the much larger fleet of projects that should come online shortly. So additional time to rework this approach may be warranted.

ii. MnSEIA ALSO TAKES ISSUE WITH SEVERAL OF THE ASSUMPTIONS WITHIN XCEL'S PROPOSED METHODOLOGY FOR FORMULATING A PV DEMAND CREDIT PER KW.

If the Commission wishes to approve a methodology similar to what Xcel has filed, then MnSEIA suggests several changes to the methodology. As part of this process, MnSEIA has retained expert witness Tom Beach, of Crossborder Energy, to evaluate Xcel's methodology.

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[7] *See* PV DEMAND CREDIT RIDER METHODOLOGY, Docket No. E-999/CI-15-115, Doc. Id. 201810-147188-01 at 4, Table 2 (Oct. 19, 2018);

[8] 55, 88 or 115 depending on who you ask at Xcel; 115 was stated at the MnSEIA conference, 88 was highlighted on a slide presented at a MnSEIA meeting and 55 is the reported number. We do not mean to imply misfeasance from Xcel, but instead the actual number depends on where the projects are in the queuing process and this results in ambiguities.

[9] This is similar to the challenges with the recent community solar transition to real fleet data for the 2019 Value of Solar Calculation (Order pending). In that instance, the Commission found there was insufficient data to warrant a change to real fleet data. Similar disparities exist here.

Tom formulated an alternative Table 2 for the Commission's review. His changes are highlighted in yellow, and MNSEIA comments below on each proposed change:

	Proposed Methodology - PV Demand Credit per kW-Mo				
Line		Xcel Proposal	Crossborder Revised		Comments
a	Levelized CT Cost	$ 4.54	$5.06		Use 50/50 mix of greenfield & brownfield, per Dakota Range
b	Embedded Transmission Cost	$ 3.47	$ 3.47		
c	Embedded Distribution Cost	n/a	$ 2.35		Customer-developed, behind-the-meter solar also avoids this
d	Total G, T & D	$ 8.01	$ 10.88	*a+b+c*	
e	Line Losses	6.65%	6.65%		
f	Total with Losses	$ 8.54	$ 11.60	*d*(1+e)*	
g	Future Need Timing Factor	60%	100%		Currently-approved IRP assumes continued development of, and immediate need for, customer-sited solar.
h	Future Need Adjusted Total	$ 5.13	$ 11.60	*f * g*	
i	MISO ELCC	50%	50%		
j	ELCC Adjusted Total	$ 2.56	$ 5.80	*h * i*	
k	Reduced Billed Demand Value	$ 0.41	$ 0.41		Temporary freeze on this line item until restudy completed.
l	Demand Credit per kW	$ 2.15	$ 5.39	*j - k*	

The details for each of the changes are included below:

1. Higher CT Capacity Cost

Xcel's CT Capacity Cost is about as low as it could possibly be, to a point of unjust valuation. The $4.54 per kW-month value is for a CT on a brownfield site, with no gas or electrical interconnection costs, no water costs, low capital costs per kW for a new H-class turbine that has not yet been used in the U.S. for a simple-cycle plant,[10] and very low fixed O&M

[10] The only active project in the U.S. using an H-class turbine in a simple-cycle configuration of which we are aware is NRG's Canal 3 project in Massachusetts, which is still under construction. The Brattle Group's April 2018 study *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date* (hereafter, "Brattle Study"), at page 17, cites the Canal 3 project and the Puente project in California as using H-class turbines, but the Puente project has been cancelled. Furthermore, the Brattle Study (at Table 9) cites low-end capital costs for H-class combustion turbines as $217.3 million for a 321 MW CT, or $677 per kW, even excluding costs for land and for gas and electric interconnections. This is more than 50% higher than the CT costs that Xcel used. The Brattle Study also cites (at Table 13) fixed O&M costs of at least $4.4 million per year versus Xcel's $0.4 million, for CTs of comparable size. Xcel's CT costs are taken from its response to MNSEIA's Information Request No. 2 and

costs. Conversely, Xcel's CT costs for a greenfield site are closer to $5.58 per kW-month.[11] Our approach uses an average between Xcel's greenfield and brownfield costs from its recent Dakota Range filing.

2. No avoided distribution capacity costs

The commercial customers who receive the capacity credit are installing behind-the-meter (BTM) solar that can defer capacity-related costs for distribution as well as generation and transmission. Xcel's capacity credit calculation does not include distribution capacity costs, even though BTM solar can reduce peak loadings on the primary distribution circuits and substations that serve commercial customers. Avoided distribution capacity costs are one component of the Commission's value of solar methodology, and thus should be included in the capacity credit. Our spreadsheet adds the embedded distribution costs ($2.35 per kW-month) that are comparable to the embedded transmission costs that Xcel uses.

3. Future need adjustment

Xcel discounts the solar capacity credit by a 60% "future need adjustment" factor based on an assertion that it does not need capacity until 2025. The 60% factor is the ratio of (1) the 25-year present value of CT-based capacity costs assuming zero capacity value until 2025 and (2) the 25-year present value of CT-based capacity costs assuming capacity is needed immediately. Our objection to this adjustment is that the Commission's decision in Xcel's last IRP (January 2017) found that the utility had an immediate need for new renewable resources.

This need also assumed that Xcel would be adding regular amounts of customer-sited, BTM solar resources over the last IRP's planning horizon.[12] The solar customers who would receive this credit are exactly the ones that are now coming on-line to meet this identified and approved need. Today, in its capacity credit calculations, Xcel is trying to discount this solar capacity based on an updated capacity position that it plans to submit later this year in its 2019 IRP, which apparently will push out its capacity need until 2025. It might make sense to consider this "future need adjustment" factor after the 2019 IRP has been approved, but it is

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appear to be in 2018 $. The CT costs in the Brattle Study assume a 2022 on-line date and 2022 $, but this difference in timing cannot account for the wide disparity in CT costs between Xcel and Brattle.

[11] *See* Table 13 of Attachment C in the application for approval of the Dakota Range III wind PPA.

[12] *See* Xcel's 2016-2030 Upper Midwest Resource Plan, at Table 2 (p. 16 of 102), showing Xcel's Preferred Plan adds 13 MW per year of "customer-driven small solar" in 2019-2020, with increasing amounts every year thereafter and a total of 506 MW over the 2015-2030 planning period.

unfair to apply it prematurely to solar customers who now are meeting the need identified in the last approved IRP. We would set the "future need adjustment" factor to 100%.

To MNSEIA's knowledge, this factor has not been included in past iterations of the PV demand credit. Moreover, the PV demand credit is based on a 25-year levelized cost for CT capacity, yet the credit is paid to the customer for only six years, even though the customer is installing solar that will provide capacity to the system – to the benefit of all ratepayers – for 25 years. On a present value basis, assuming the 6.43% discount rate that Xcel uses, the six-year term of the program provides a credit to the solar customer that is just 40% of the value of the 25-year capacity that the new solar project provides. Even with the 15-year program term that MNSEIA proposes below, the solar customer would receive only 77% of the value of the capacity that they provide to the system. Thus, the program already includes a significant benefit for ratepayers that hedges against the possibility that capacity may not be immediately needed.

Furthermore, Xcel's "future need adjustment" mistakenly assumes that capacity has zero value until many years in the future. New capacity has an immediate value to the utility in the form of reducing its potential need to procure capacity on the spot market, or allowing the utility to earn greater revenues from market sales of capacity. While Xcel may not have a general need for capacity, the utility can encounter specific days when they need spot capacity. Additional solar capacity can reduce the frequency of these needs, as well as provide incremental revenues from market sales of capacity.

4. Reduced Billed Demand Value

This item, as was referenced earlier in these comments, is predicated on only a handful of systems that were installed under a previous programmatic framework. We are not suggesting a specific adjustment to this reduction in the credit at this time, but instead think that Xcel should restudy this component in a year after the approval of its new rider, with the data from a much larger set of projects. The reduction value should remain at $0.41 until the new study is completed to ensure a conservative application of the credit value.

iii. ANY NEW RATE COMING FROM THIS PROCESS WILL HAVE TO BE IN CONSIDERATION OF A GREATER PROGRAM.

MnSEIA seeks to highlight that while this conversation and the general agreement was removed from some of the underlying challenges with the PV Demand Credit Rider, those challenges still remain. This conversation cannot overlook the need for a strong program in addition to just a rate element.

1. Term Length

First, the current 6 year term length is permitting some projects to pencil that previously would not have been financeable. However, additional term-length certainty is important for any viable program. The Community Solar Gardens program has 25-year terms. Many of the Xcel

PPAs for wind and solar have 20+ year terms. There is no reason that this program should not have a similar term length associated with the credit. Customers can then base their purchasing decisions on contracts with a reasonable expectation that the program's length will be closer to the expected economic lives of their systems.

If this credit is going to be recalculated based on data from Xcel's rate cases, then we suggest that the term-length be tied to the frequency of those cases. Our general understanding is that rate cases are every three years, and so a customer's contract should be tied to a multiple of 3 to ensure seamless transition from one credit amount to the next. As such, we propose a 15-year term where the credit is fixed.

2. Storage

One of the oddities around the PV Demand Credit Rider is Xcel is acknowledging, at least currently, that solar provided during peak periods is a credit worthy benefit to the utility. However, the current PV Demand Credit Rider does not permit customers to add storage and still qualify for the rider even though a C&I customer that has both solar and storage is able to deliver even more capacity (and firmer capacity) to the utility at the designated peak periods. Thus, we request that the Commission find that storage installation is a permissible use for the Rider.

3. Customer Data Access

Currently it is quite challenging for our members to get actual use data from Xcel for specific customers. This requires developers to make estimates about the value of the credit. If this program is going to be a success over the long-term, customers will need better data upfront with which to make purchasing decisions. We hope the Commission will require Xcel to provide accurate and specific PV Demand Credit Rider data to the prospective C&I customers that request it.

iv. PROPOSED DECISION OPTIONS

A. Restudy Requests

1. Require Xcel to restudy the PV Demand Credit Rider methodology and focus on where C&I solar customers are overbilled on their demand charges. The November 2, 2017 negotiated agreement will be modified by altering the 2024 end date to 2025; or
2. Require Xcel to modify its PV Demand Credit Rider to mirror its program offering in Colorado, and while Xcel is modifying its rider for compliance, the November 2, 2017 negotiated agreement will be modified by altering the 2024 end date to 2025; or
3. Require Xcel to restudy its Reduced Billed Demand Value by December 31, 2019 to better account for the new projects that are currently coming on line and to improve its data set, and in the meantime preclude Xcel from applying the $0.41 reduction.

B. Changes to Xcel's Proposed Methodology if Xcel is not required to restudy (although A3 could be in conjunction with the options below).

1. Use $5.06 per kW-month as the Levelized CT cost to better align with the average costs associated with both brownfield and greenfield CTs;
2. Provide a $2.35 per kW-month credit for Embedded Distribution Costs; and
3. Change the future need timing factor to 100% to reflect current immediate needs.

C. Additional Rider Changes

1. Provide customers with a 15-year term associated with each PV Demand Credit Rider vintage year;
2. Permit Energy Storage that is paired with PV to participate in the program; and
3. Request Xcel to provide prospective customers with complete data upfront about their demand charges and how they are calculated to ensure informed customer choice.

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