BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

In the Matter of the Commission Staff's Request to Investigate Northern States Power Company dba Xcel Energy's Fuel Clause Rider	**)** **)** **)**	**Docket No. EL16-037**

TESTIMONY AND EXHIBITS OF KAVITA MAINI ON BEHALF OF THE COMMISSION STAFF

July 28, 2017

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I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Please state your educational and professional background.

A. I am an economist with over 25 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with Master's Degrees in both Business and in Applied Economics. From 1991 to 1997, I worked for Wisconsin Power and Light Company ("WPL") as a Market Research Analyst and Senior Market Research Analyst. In this capacity, I conducted process and impact evaluations for WPL's Demand Side Management ("DSM") programs. I also conducted forward price curve and asset valuation analysis. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc., in San Diego, California, a consulting firm specializing in DSM evaluations and neural network forecasting. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. In this role, I was responsible for providing energy consulting services to commercial and industrial customers in the areas of electric and natural gas procurement, contract negotiations, forward price curve analysis, rate design, and on-site generation feasibility analysis.

Since 2002, I have been an independent consultant. I consult in the areas of class cost of service studies, rate design, integrated resource planning and resource acquisition,

revenue requirement related issues, Midcontinent Independent System Operator ("MISO") related matters and various policy matters including fuel cost recovery. On behalf of the Wisconsin Industrial Energy Group, I have been an End Use Sector representative at MISO since 2006. I represent the End Use Sector at the Advisory Committee and Planning Advisory Committee ("PAC"). The PAC is responsible for providing policy guidance to MISO relating to transmission planning. As such, this includes comprehensive vetting related to MISO's use of futures scenarios and input assumptions in its screening and hourly production cost models.

Q. Have you testified before the South Dakota Public Utilities Commission?

A. Yes. I have represented Commission Staff before the South Dakota Public Utilities Commission ("Commission") in various cases associated with evaluating the need for acquisition of generation resources.

Q. Have you participated in utility related proceedings in other jurisdictions?

A. Yes, I have testified before a number of state regulatory commissions, including Wisconsin, Minnesota, Missouri, Iowa and North Dakota. I have also submitted technical comments on a variety of issues related to resource planning, energy policy including but not limited to fuel cost recovery, revenue allocations and rate design in transmission and renewable rider proceedings. I have also provided technical comments and/or represented the Wisconsin Industrial Energy Group in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities. Exhibit_KM-1 identifies the proceedings in which I have been involved at the state and FERC level.

Q. **On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Commission Staff.

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to address Northern States Power Company's ("Xcel Energy" or "Company") testimony in response to Staff's Motion to Show Cause regarding the current or potential cost recovery associated with the acquisition of Aurora Solar, Marshall Solar and North Star Solar power purchase agreements ("PPA"), (also called "New Resources"). Specifically, I evaluate whether the Company witnesses Mr. Aakash Chandarana and Mr. PJ Martin sufficiently demonstrate that the decisions to acquire these PPAs were prudent based on Staff's standard of review and analysis.

Q. What is Staff's Standard of Review and Analysis?

A. Staff witness Jon Thurber's testimony provides Staff's recommended standard of review for evaluating prudency of acquired resources. The key elements are as follows:

- The underlying costs in the fuel clause rider should be based on resource acquisitions that were (a) absolutely necessary or needed, and (b) economic and reasonable;
- While the Commission is required to evaluate reasonableness and need, the Commission can approve cost recovery of generation resources that are not least cost. However, in order for the Commission to deviate from the needs based and least cost paradigm, Xcel Energy has the burden to provide adequate and compelling support regarding other factors to justify such deviation.
- Each discrete generation resource recovered through the fuel clause should be reviewed on a case-by-case basis; and

- The facts and circumstances available at the time the decision to proceed with a resource addition are to be considered when evaluating prudency.

Q. Please summarize your testimony.

A. I evaluated the prudency of acquiring Aurora Solar, Marshall Solar and North Star Solar by considering a number of factors including whether:

a. The PPA based resources were acquired to fulfill an energy or capacity need;
b. They were least cost compared to other alternatives; and
c. Other considerations such as environmental benefits, hedging against natural gas price volatility, the federal Investment Tax Credit and gaining experience would justify deviating from the need and least cost framework.

Based on the evaluation discussed in detail below, I found that the Aurora Solar, Marshall Solar and North Star Solar PPA acquisitions cannot be considered prudent or reasonable.

II. ROLE OF INTEGRATED RESOURCE PLANNING

Q. How is integrated resource planning generally conducted when a utility's service area includes one state?

A. Generally speaking, integrated resource planning for a utility serving one jurisdiction consists of evaluating supply and demand side solutions over a long term (such as 10 to 20 years) to ascertain which solution is best or results in least cost to consumers to

address capacity, energy and policy needs, subject to federal and the specific state's statutory and regulatory requirements.

Q. Does the concept of integrated resource planning change when a utility's service area such as Xcel Energy includes multiple jurisdictions?

A. Not really. Conceptually, the same process of evaluating the need to acquire additional resources should be followed. Planning as an integrated system becomes complex since it requires the utility to consider the needs and priorities of each of the jurisdictions that it serves. At the same time however, there is a common denominator inherent in all the jurisdictions such as North Dakota, South Dakota and Minnesota.

Q. What is the common denominator?

A. I believe that each jurisdiction recognizes the needs based and least cost planning principle of resource acquisition. While each jurisdiction places a different value on environmental policy and related mandates, all jurisdictions recognize the basic principle of acquiring resources based on energy or capacity need and least cost planning. This common denominator signifies the importance and value associated with an integrated system. Customers in all jurisdictions benefit because of the needs plus least cost acquisition and economies of scale and diversity savings. Provided Xcel Energy procures resources in this manner, it should not be at risk of cost recovery in any of the three jurisdictions.

Q. If one jurisdiction has a stringent policy requirement driving certain resource selections, does this mean that resource planning of an integrated system can only be

achieved if all other jurisdictions accept the cost responsibility associated with the resulting resource selection?

Not necessarily. Mr. Chandarana seems to suggest that in order to remain part of the integrated whole, the South Dakota customers must accept the costs associated with resource selections acquired due to stringent requirements established by another jurisdiction – which essentially means that the South Dakota jurisdiction must be forced to adopt the same stringent requirements of another jurisdiction and ignore its own statutory obligations. This rationale seems neither fair nor equitable and puts the South Dakota jurisdiction in an untenable position. Consequently, on behalf of South Dakota customers, Mr. Thurber expresses that "Based on how Xcel Energy has defined its integrated resource planning process and allocates generation costs across its state jurisdictions, the value of the integrated system is diminishing to South Dakota customers because the cost of the most stringent state's uneconomic compliance mandates and regulatory decisions is being allocated to South Dakota."

In order to avoid such circumstances, the Company should recognize and respect that all jurisdictions do not share the same value on certain state specific mandates or policies. In my opinion, instead of a choice between extreme options such as either being part of an integrated system (and adopting the stringent requirement and resulting cost implications) or completely divesting from it, a more optimal and equitable solution to consider is to monetize the value associated with a specific state's mandate or policy and direct assign to the specific jurisdictions that show a preference for it.

III. AURORA SOLAR PPA

Q. Please briefly describe the Aurora Solar Project.

A. The Aurora Solar Project is a 100 MW (ac) project with a targeted in-service date of December 2016 and consists of distributed solar facilities located at up to 24 sites in Minnesota, ranging in size from 2 to 10 MW. As noted by Mr. Martin, the projected capacity factor is approximately 22% and the project developer has committed to 71 MW accredited capacity. Xcel Energy entered into a 20 year PPA arrangement with a solar developer as directed by the Minnesota Public Utilities Commission ("MPUC"). This project became fully operational in June 2017.

Q. Please describe your overall approach in evaluating the prudency of the Aurora Solar resource.

A. Consistent with Staff's standard of review for prudency, I determined the necessity of acquiring resources and if needed, whether acquiring the Aurora Solar Project was least cost compared to other alternatives. I also assessed whether Xcel Energy's demonstration of environmental and other benefits justify deviation from the needs based and least cost paradigm. I provide my recommendations after a consideration of these factors.

1. EVALUATION OF NEED

Q. Please explain if there was a need to acquire resources as early as 2017.

A. In short, no – while Xcel's forecasts in 2010 and 2011 showed a capacity deficiency, subsequent Resource Plan updates provided by the utility in 2013 showed a decline in need and in 2014, Xcel Energy forecasted a surplus through 2023. The specific details are discussed below.

A capacity shortfall was identified in the 2010 Resource Plan submitted to the MPUC in August 2010 in Minnesota Docket E002/RP-10-825. In March 2011, the Company submitted a Certificate of Need ("CON") petition in Minnesota Docket E002/CN-11-184 for repowering the Black Dog Generating Plant ("Black Dog") on the basis of need identified in the 2010 Resource Plan. Xcel's CON petition consisted of approximately 450MW of incremental capacity from the Black Dog repowering project with a proposed in-service date in 2016. However, Xcel filed a motion to withdraw this filing in December 2011 because the Resource Plan update showed that the Company could no longer support the resource need as presented. The Company attributed the decline in need to slower economic growth and loss of wholesale customers. The projected growth for peak demand and energy was reduced from 1.1% and 0.9% in the Resource Plan to 0.7% and 0.5% respectively. The Company indicated that "Since the underlying need for the capacity is no longer present, it is not prudent to proceed with this docket." The MPUC's order issued in November 2012 required closing of the docket and establishing a new proceeding (Docket E002/CN-12-1240), ("Competitive Acquisition Process" or "CAP") to conduct further analysis of size, type and timing of adding resources.

The Fall 2011 Resource Plan update showed the need for approximately 150 MW in 2017 increasing to 500 MW in 2019. However, a subsequent update in the CAP docket in

September 2013 continued to show a decline in need - down to 93 MW in 2017 and 307 in 2019. [1]

Instead of a deficiency, the Fall 2014 Resource Plan update in the CAP proceeding showed a surplus of 250 MW in 2017 and 100 MW in 2019. Further, this surplus excludes accounting for the following:

a. A no cost alternative such as adding 73 MW of accredited capacity to the Manitoba diversity agreement for the period 2017-2019; and

b. A projected $3 million to $5 million expense for retaining instead of retiring the Blue Lake units 1-4 (153 MW accredited capacity) for the period 2020-2023.

Q. What was the Company's perspective regarding need in Fall 2014?

A. The Company's comments in the Minnesota docket indicated that the prudent course of action was to delay the acquisition of resources to 2019 or beyond. The following are statements from Xcel Energy to substantiate this observation:

September 23, 2014, Xcel Energy's Compliance Filing in the CAP proceeding, page 11:

> Even with the uncertainty in resource need assessments, our analysis leads us to conclude that there is high probability we will have more than adequate generating resources through 2018 or 2019, and perhaps through 2023. If the Commission agrees with our reassessment of our capacity needs, the terms and timing of the Power Purchase Agreements we have negotiated no longer coincide with our anticipated need.

November 3, 2014, Xcel Energy's Reply Comments in CAP proceeding, page 1

> In these Reply Comments, we continue to:

[1] See Steven Wishart Direct Testimony, September 27, 2013, page 2 in Docket E002/CN-12-1240).

> Caution that the assessments of our expected capacity needs in the 2017 to 2019 time period throughout this proceeding have continued to decline and no longer support a capacity addition to our system. The most prudent course for our customers is deferring the addition of new generation for capacity purposes to 2019 or beyond.
>
> November 3, 2014, Xcel Energy's Reply Comments in CAP proceeding, page 3

> Our Need Update indicates that our capacity need for the 2017 to 2019 time period is not materializing. This changed assessment is not driven by only a modest change in the customer demand forecast, but rather is primarily due to the greater confidence in the MISO resource adequacy construct. We believe that our September 23rd Need Update appropriately raises the issue that a delay in adding capacity resources to our system is warranted until at least 2019, if not later, and we have therefore proposed ways of addressing that delay.

Q. **Notwithstanding the forecasted surplus, did the Company recommend a conservative course of action?**

A. Yes. The Company proposed the following cost effective approach as part of its contingency plan:

1. Xcel Energy identified two existing resources with no or low cost modifications that would serve as a "bridge to meet the small need that may materialize in the 2018-2023 period."[2] This consisted of the following:
   - Negotiate an additional 73 MW of accredited capacity with Manitoba Hydro as part of a diversity exchange agreement;[3]

[2] See Xcel Energy Reply Comments, page 1, docket E002/CN-12-1240, November 3, 2014.
[3] This agreement to an existing arrangement that Xcel Energy had with Manitoba Hydro in which Manitoba Hydro provides the Company 350 MW of generation capacity during the summer; in exchange, Xcel provides 350 MW to Manitoba Hydro in the winter when they experience peak demand.

- Extend the lives of Blue Lake units 1-4 with minimal capital expenses, which would add 153 MW of accredited capacity for the period 2020-2023.

2. Xcel Energy also recommended that it work with the PPA developers who provided bids in the CAP proceeding in developing flexible terms and conditions to address a delay in need.

Q. What was the outcome of the CAP proceeding?

A. The MPUC reaffirmed its reliance on the Fall 2011 Resource Plan update in approving the Aurora Solar project along with other thermal resource acquisitions.

Q. Did the Company appeal this decision?

A. No; Mr. Chandarana testifies that the Company recognized that the MPUC's decision was well reasoned. Mr. Chandarana states in part:

> At the time, there was significant volatility in our load forecasts due to the impacts of the Great Recession of 2008. If load growth had bounced back to the 1 to 1.5 percent growth we had been experiencing prior to the recession, the capacity need for which the CAP Proceeding was initiated could have materialized.

Q. In your opinion, is this reasoning persuasive?

A. No. As discussed above, the Company provided compelling evidence in the CAP proceeding that there was a steady reduction in capacity need and the prudent approach was to defer action. In encapsulating the trend of its capacity need, Xcel Energy noted the following in part:

> The trend in our need forecasts from our 2012 update of the 2011 forecast in our Resource Plan docket, to the 2013 forecast we relied upon in this proceeding, to the 2014 forecast we filed on September 23rd, is a steady reduction in our capacity need for the 2017-2019 time period. [4]

Further, the Company had also provided no to low cost options as part of its contingency plan to capitalize on existing resources (the Manitoba Hydro exchange agreement and life extension of Blue Lake units 1-4) in the event there was a deficiency instead of a surplus.

I would also note that the possibility related to load growth bouncing back was not a new issue that Xcel Energy somehow could have omitted to consider when it updated its analysis and submitted its recommendations in Fall 2014.

Q. What do the above based findings suggest regarding a need to acquire the Aurora Solar resource?

A. The findings suggest that the Company did not have a capacity deficiency starting as soon as 2017 and that Xcel Energy would be able to meet its capacity needs by using existing resources through 2023 in lieu of acquiring the Aurora Solar resource. Thus, there was no need to acquire this resource to address a capacity need deficiency as soon as 2017.

2. EVALUATION OF LEAST COST

Q. Assuming for arguments sake that that there was a demonstration of need to acquire the Aurora Solar resource, does the Company agree that that this resource was not a least cost resource?

[4] See Xcel Energy Reply Comments, page 3, docket E002/CN-12-1240, November 3, 2014.

A. Yes. Both Company witnesses, Mr. Chandarana and Mr. Martin testify that the Aurora Solar resource is not least cost. Mr. Martin noted that "none of the analyses we conducted suggest that the Aurora Project is the least cost resource to meet our capacity needs."

Q. Did you review the results of the analysis?

A. Yes, I first evaluated the results of the present value of the revenue requirements ("PVRR") without assuming externalities that Xcel Energy submitted to the North Dakota Public Service Commission ("NDPSC") in docket PU-15-095. This is because the scenarios presented in the NDPSC docket reflect pure economic analysis without speculation or assumption on other factors such as carbon value. Next, I evaluated the results of the present value of the societal costs ("PVSC") results submitted in the MPUC proceeding, which assumes a carbon price of $21.50 per ton.

Q. What do the results indicate?

A. The results are as follows:

First, the PVRR results presented in the NDPSC docket show that Aurora Solar is not a least cost resource on a stand-alone basis in either the base case or any of the key sensitivities shown in Table 4 of Mr. Martin's testimony. Table 1 shows these results. It is worth noting that even under the High Gas sensitivity, the Aurora Solar PPA was not cost effective.

Table 1: Net PVRR Impact of Aurora Solar ($ Millions)

Sensitivities	Base	Low Gas	High Gas	Market Off	MN Assumption (PVSC)
Aurora Solar PPA v. Base Case with ND Assumptions	$62	$76	$44	$49	$35

Second, the PVSC results presented in the MPUC docket (assuming a carbon price assumption of $21.50 per ton) show that the Aurora Solar project was not least cost on a stand-alone basis (see MN Assumption sensitivity above). Further, Mr. Martin also testified that the Aurora Solar project was also not in the top 20 portfolio of project combinations due to its higher cost in comparison to the other proposals submitted in the CAP proceeding.

Q. What was the Company's position in the MPUC CAP proceeding regarding the Aurora Solar PPA?

A. Regarding the Aurora project specifically, the Company recommended that the Commission take a holistic view when determining the acquisition of this resource within the context of its 187 MW Solar Portfolio petition (MPUC docket E-002/M-14-162). I will discuss this issue in the next section. It is worth noting here, however, that from a cost perspective, the Aurora solar project was not least cost when compared to other solar projects acquired through a competitive solicitation around the same time period.

Q. What are your conclusions regarding the Aurora Solar PPA so far?

A. My conclusions are as follows:

First, the Company's own analytical findings suggested a capacity resource was not needed in 2017 and coupled with bridge resources such as the Manitoba Hydro diversity exchange resource of 73 MW and life extension of the Blue Lake units 1-4, the Company could defer additions until 2023;

Second, assuming arguendo that there was a capacity need, the Aurora Solar PPA was not the least cost resource compared to other alternatives to address this need, in scenarios with and without externalities;

Third, the Aurora Solar PPA was not least cost compared to other solar projects acquired through a competitive solicitation around the same time period.

3. EVALUATION OF OTHER FACTORS

Q. If the Aurora Solar PPA cannot be justified on the basis of the least cost plus need paradigm, what additional justification does Xcel Energy provide to demonstrate that the Aurora Solar PPA is a prudently acquired resource?

A. Mr. Chandarana relies on the following qualitative factors to demonstrate prudency and deviate from a least cost plus needs paradigm:

1. Hedging against natural gas price volatility
2. Hedging against future environmental regulation
3. Taking advantage of the 30 percent investment tax credit (ITC)
4. Gaining experience in managing utility scale solar with multiple interconnection points on the utility distribution system

Q. What is your response regarding these factors?

A. I do not find the Company's support regarding qualitative factors persuasive to deviate from the least cost plus needs paradigm because of the following:

- Hedge against natural gas price volatility: As noted in Table 1, the PVRR even in a High Gas sensitivity case suggests that the Aurora Solar resource is not cost effective.

Further, neither Mr. Chandarana nor Mr. Martin provided any analysis to demonstrate that hedging against natural gas price volatility with this resource would be more cost effective than other hedging alternatives;

- Hedge against potential environmental regulations: The PVSC results shown in Table 1 (Minnesota Assumption) are based on a $21.50/ton carbon assumption and indicate that the Aurora Solar resource is not cost effective even under these circumstances. Further, neither of the Company witnesses provided any quantifiable evidence to demonstrate that hedging against potential environmental regulations with this resource would be more cost effective than other options.
- Capitalizing on the 30 percent ITC: This benefit can only be found compelling if the result was a least cost solution to address need. However, as noted earlier, the Aurora Solar PPA was not a least cost acquisition;
- Gaining experience in managing utility scale solar on the Company's distribution system: Xcel Energy had the ability to gain experience for multiple interconnections on the distribution system through community solar gardens. Further, gaining experience at the cost of acquiring an expensive project is a difficult trade off to rationalize.

Q. Based on your evaluation discussed above, is the acquisition of the Aurora Solar PPA prudent?

A. No. Xcel has not demonstrated the prudency of acquiring the Aurora Solar resource based on my evaluation discussed above.

III. The 187 MW Solar PPA Portfolio

Q. Please briefly describe the 187 MW Solar PPA Portfolio.

A. The 187 MW Solar PPA Portfolio (or "Solar Portfolio") was acquired through a competitive acquisition and RFP process initiated in April 2014. Xcel Energy submitted a petition (MPUC docket E-002/M-14-162) in October 2014 for approval of the following three utility-scale, solar photovoltaic generation projects:

- Marshall Solar – a 62.25 MW project located in Minnesota with an expected in-service date in late 2016 and term of 25 years.
- MN Solar I- a 24.5 MW project located in Minnesota with an expected in-service date in late 2016 and term of 25 years; and
- North Star Solar – a 100 MW project located in Minnesota with an expected in-service date in late 2016 and term of 25 years.

This Solar Portfolio was approved by the MPUC in March 2015. Mr. Martin notes that Marshall Solar and North Star Solar became fully operational in January 2017 and December 2016, respectively. MN Solar I exercised its right to terminate its PPA after it was approved (in May 2016) due to issues in obtaining an interconnection agreement.

Q. Are you evaluating the prudency of acquiring all three solar projects included in the Solar Portfolio?

No, since the MN Solar I PPA was terminated, the Company will not need to seek recovery for this project and therefore, evaluating prudency for this resource is moot. However, since at the time of the petition in Minnesota the Company was proposing the

187 MW Portfolio, and Xcel's quantitative analysis included all three projects, I evaluated the prudency of the portfolio.

Q. Please describe your approach in evaluating the prudency of the Solar Portfolio.

A. I determined whether this Portfolio was needed or necessary to satisfy a capacity or energy need and if needed, whether acquiring this Portfolio was least cost compared to other alternatives. I also evaluated the economic analysis and qualitative factors to assess whether Xcel Energy has met its burden of justifying deviation from the needs based and least cost paradigm.

1. EVALUATION OF NEED AND LEAST COST

Q. What was the basis of acquiring the Solar Portfolio?

A. The basis was to fulfill Minnesota's Solar Energy Standard[5] ("SES") or mandate which requires that at least 1.5% of a utility's total retail electric sales to retail customers (excluding specific industrial customers)[6] in Minnesota is generated by solar energy by the end of 2020.[7] The Minnesota SES also includes a goal that by 2030, 10% of the retail electric sales in Minnesota be generated by solar energy. Minnesota is the only state out of all the states in the Xcel Energy system under the MISO footprint (Michigan, Wisconsin, North Dakota, South Dakota) with a specific solar energy requirement in addition to a renewable energy mandate (see Xcel Energy's Response to Staff Data Request 5-5).

[5] MSA 216B.1691.2f
[6] *Id.* sub (d).
[7] See Xcel Energy response to Staff Data Request 2-1.

Unlike the Aurora Solar resource which was being evaluated to address the need for a capacity resource in the Minnesota proceeding, the Solar Portfolio was a result of a competitive bid RFP process that sought solar projects for SES compliance. [8]

Without the SES, therefore, the Company would not have issued an RFP to acquire these resources since there was no need identified other than compliance with Minnesota's SES.

Consequently, acquisition of this portfolio was not necessary or needed but for the SES compliance. Further, since the objective of the competitive bidding RFP process was to solicit proposals for the purpose of SES compliance and not to satisfy need, there is no evidence to support that the solar projects were least cost compared to other resource alternatives.

Q. At the time that Xcel Energy issued the Solar Portfolio RFP, what was the Company's projection of the MWs of solar resources required to meet Minnesota's SES by the end of 2020?

A. The Company projected 250 MW of solar resources were required to meet the Minnesota SES obligation[9]. At the time the RFP was issued, the Company's plan was to acquire 150 MW as utility scale solar and the Company anticipated the remaining 100 MW would be fulfilled by Community Solar Gardens and other customer distributed solar projects.

Q. Were other solar projects under consideration at the same time as the Solar Portfolio?

A. Yes. As discussed earlier, the Aurora solar resource was under consideration in the CAP proceeding. The Company urged the MPUC in its Solar Portfolio petition and in the

[8] See Mr. Martin's testimony, page 29.lines 11-16.
[9] See Xcel Energy's response to Staff Data Request 5-6

CAP proceeding that a holistic view of the solar acquisition should be considered. That is, the MPUC should select the 187 MW Solar PPA Portfolio because it was more cost effective than the Aurora Solar resource to meet the SES. However, the Company argued that if the MPUC decided to approve the Aurora Solar resource, then the North Star Solar project should not be selected. In this manner, the Company would have 187 MW in total utility scale solar, which along with the distributed solar resources would be sufficient to fulfill the SES by 2020.

Q. What was the result of the MPUC decision?

A. The Company essentially was on track to procure an excess of 100 MW of additional solar resources beyond that needed to comply with the 1.5% solar energy requirement - 100 MW of the Aurora Solar resource + 187 MW portfolio for a total of 287 MW + 100 MW of anticipated Community Solar Gardens and other customer distributed solar projects. In fact, regarding the customer based solar programs, in supplemental information provided to MPUC, the Company indicated that

> We further clarify that we believe that our **100 MW** estimate is conservative, in light of the robust initial response to our Community Solar Gardens program, and that distributed generation solar units will add considerably more solar resources to our system. [10]

Thus, not only was there no need to procure such resources to fulfill native load obligations, the procurement would result in over 100 MW more than the Company required to meet the SES compliance by 2020.

2. EVALUATION OF ECONOMIC ANALYSIS

[10] See Xcel Energy Reply Comments – Supplemental Information, December 19, 2014, DOCKET NO. E002/M-14-162.

Q. Since this Portfolio cannot be considered prudent on the basis of the needs and least cost criteria, what factors did the Company use to justify deviation from this criteria?

A. The Company based its justification on the differences of the PVRR (i.e., without externalities) and PVSC (i.e., with externalities) results of total system costs with and without the Portfolio as well as other qualitative factors such as hedging against natural gas price volatility and environmental risks and capitalizing on the 30% ITC credit.

Q. Prior to discussing the results of the economic analysis, please explain the challenges associated with modeling solar generation in the analysis.

A. Solar resources are intermittent and dependent on weather. As is conventionally known, capacity factors are typically low (less than 25%). In the modeling analysis, assumptions are made regarding the solar output profile, which stays static over the long term horizon. However, we know that weather changes directly impact solar output and since there is a high level of uncertainty regarding weather conditions, the resulting solar output correspondingly also has a high level of uncertainty. It is my understanding that a static hourly solar profile is used in the modeling analysis, meaning that each year the solar resource is producing the same level of output at the same time as the previous year. I am providing this context to recognize that aside from a long term modeling analysis being fraught with numerous assumptions and resulting uncertainty, there is an additional layer of uncertainty due to the intermittency of the resource in comparison to a thermal resource evaluation.

Q. Please provide your assessment of the PVRR results.

A. As discussed in the evaluation of the Aurora Solar resource, the PVRR results represent pure economic impacts meaning that there are no assumptions on externalities such as carbon costs. Table 2 shows the differences in the PVRR results of total system costs with and without the Portfolio for the reference case and various sensitivity cases.

Table 2: Difference in PVRR With and Without the Solar Portfolio

	Reference Case	Low Gas Cost	Markets Off	+2.5% Capacity Factor	-2.5% Capacity Factor
Change in PVRR Cost ($ Millions)	$14	$43	($5)	$25	$6

My key takeaways from this analysis are as follows:

- The results indicate that the acquisition of the Solar Portfolio results in higher costs to the system by $14 million indicating that the costs of adding this portfolio are higher than the benefits. Except for the Markets Off sensitivity case, other sensitivity cases show that the costs exceed the benefits;
- The Markets Off scenario is unrealistic because the Company is a market participant in the MISO market;
- While both the capacity factor sensitivity cases show that the benefits do not exceed the costs, the results suggest that the higher PPA payments resulting from delivering more output in the plus 2.5% capacity factor sensitivity case, lowers the economics. The Company attributes this result to the PPA pricing being structured on a $/MWh basis and if there is more output, the payments are more compared to the lower capacity factor sensitivity case. [11] However, this could

[11] See Xcel Energy's response to Staff Data Request 6-7.

also imply that the solar resources are not displacing high priced energy by producing more and that customers would be better off if less output was delivered, which seems counter intuitive.

Thus, from a pure economic standpoint, acquiring this Portfolio does not result in reducing costs to customers for the long term.

Q. Please provide your assessment of the environmental benefit.

A. I used the PVSC results to evaluate the environmental benefits. Table 3 shows the differences in the PVSC results of total system costs with and without the Portfolio for the reference case and various sensitivity cases.

Table 2: Difference in Total System Costs With and Without the 187 MW Portfolio

	Reference Case	Low Gas Cost	Markets Off	+2.5% Capacity Factor	-2.5% Capacity Factor
Change in PVSC Cost ($ Millions)	($47)	($16)	$14	($56)	($49)

The results indicate that assuming a carbon price of $21.50/ton, there are system benefits of $47 million in the reference case, and Mr. Martin testified that system costs break even with a $5.64/ton carbon assumption. What is devoid in this analysis, however, is that the Company has not provided any evidence to show that this Portfolio results in cost savings that are higher than pursuing other alternatives to address carbon emissions mitigation. For example, the Company had recently acquired a 750 MW wind portfolio around that time. [12] In order to consider an apples-to-apples comparison with a roughly equally sized

[12] See MPUC Order in E-002/M-13-716, E-002/M-13-603 issued on December 13, 2013.

wind project, I considered the Borders Wind project (Company owned acquisition) which has a nameplate capacity of 150MW. The Company's analysis showed that assuming a carbon price of $21.50/ton, there are system benefits of $124 million. I note that on a pure economic basis, the analysis showed system benefits of $45 million.[13] The levelized costs for each project in the 750 MW portfolio was below $29/MWh.[14]

Thus, compared to the Borders wind resource acquisition, the environmental benefit value associated with the Solar Portfolio is approximately three times less ($47 million v. $124 million). Similarly, while there is a projected $45 million in pure economic benefits by including Borders Wind ($0/ton carbon sensitivity), there is an estimated $14 million in higher costs to the system for the Solar Portfolio.

3. ITC BENEFIT

Q. Since the SES entailed compliance by end of 2020, why did the Company propose to acquire these resources as early as 2014?

A. Mr. Martin stated in his testimony that

> Issuing the RFP in 2014 helped ensure that any projects selected could meet the December 31, 2016 expiration deadline for the 30 percent Federal Investment Tax Credit (ITC), which allowed the Company to capture more attractive pricing for the projects.

[13] See the Company's initial filing in docket E-002/M-13-716, Table 2: Incremental PVRR Results from Base Case ($millions), page 19.

[14] See the Company's initial filing in docket E-002/M13-603

After 2016, the ITC was projected to decline to 10% as per the federal laws prevalent at that time. As noted above, the Company reasoned that it was best to capture the more attractive pricing.

Q. Did the ITC credit result in system wide long term net economic benefits?

A. No. As discussed above, on a pure economic basis, the PVRR results indicated that there was a net system cost of $14 million. Capitalizing on the ITC benefit justification only has merit if it also results in net system benefits on an economic basis. Further, as discussed earlier, the Company acquired at least 100 MW of additional solar resources more than required, in order to comply with the SES compliance by the end of 2020.

Q. Couldn't the additional 100 MW be used towards compliance of the 10% solar energy goal by 2030?

A. Yes, but the Company was also aware at that time that continued advancements in solar technology would significantly reduce costs. The Company noted the following in Reply Comments in the MPUC proceeding relative to capitalizing on the ITC credit:

> The countervailing consideration in the solar generation market, however, is the continuing reduction in production costs due to technology improvements. The likelihood of significant improvements in technology compensating for the reduction in federal incentives is well documented in the IHS Energy's Outlook for US Solar PV Capital Costs and Prices, 2014-2030 (October 7, 2014) (IHS Report), which we cited in our Petition. The IHS Report involved detailed econometric modeling of the principal factors impacting the existing and projected costs of solar projects, including (i.e., capital costs, cost of capital, tax incentives, operating capacity, and required energy pricing). The report shows that solar photovoltaic benchmark capital costs have fallen by about 50 percent from 2009 to 2014, and are anticipated to fall another 35 percent from the 2014 level by 2020, and a 45 percent reduction from the current level by 2030.[2] These projected capital cost savings are significant, and it appears

they will more than offset the decline, or even the possible elimination of the ITC.

I would note that as an example, wind technology has advanced significantly in the last five to ten years. For example, in Xcel Energy's case, when it acquired Nobles in 2008, the prices were drastically higher than compared to the prices in 2013 and 2016. In 2013, Xcel Energy acquired wind for less than $29/MWh and in 2016, Xcel Energy's 1550 MW petition states that the levelized costs for wind in its portfolio is under $22/MWh.[15] Thus, technological advancements are to be expected due to the natural incentive for solar resources to compete against other resources in the market place.

Q. How did the Company justify the benefit of hedging against natural gas price volatility?

A. Mr. Martin stated that 84% of the solar resource portfolio output resulted in displacing natural gas fired generation since solar output occurs in the on peak hours when natural gas fired generation is on the margin. Therefore, a solar resource acts as a hedge against natural gas price volatility.

Q. What is your perspective regarding this matter?

A. While solar resources can provide a hedge against natural gas price volatility, the Company has not provided any analysis to suggest that utilizing this resource as a hedge is more cost effective than other ways of managing the risk. In response to Staff Data Request 6-14, the Company states in part that "if the Company was not to acquire these resources, future levels of natural gas consumption and MISO market purchases would be higher, creating higher cost uncertainty for our customers system-wide." However, the Company does not explain or reconcile how the higher cost uncertainty created in the

[15] See Xcel Petition in Docket No. E-002/M-16-777, page 6.

absence of the solar resources trumps the uncertainty in the output due to the intermittent nature of these resources. Further, I would also note that since solar resources are intermittent, they may drive the demand for natural gas fired generation. In the MISO market, the solar resources are a must take resource and depending on the intermittency of this resource, intermediate or peaking natural gas fired generation would need to be in place when the solar unit stops producing. Thus, while the solar resources may be displacing the output from the natural gas fired generation, they do not replace and may in fact create the need for natural gas fired resources.

Q. What are your conclusions regarding the evaluation of the 187 MW Solar PPA portfolio?

A. My conclusions are as follows:

- The Solar PPA Portfolio was acquired for SES compliance;
- Since the objective of the competitive bidding RFP process was to solicit proposals for the purpose of SES compliance and not to satisfy need, there is no evidence to support that the solar projects were least cost compared to other resource alternatives.
- The Company acquired significantly more solar resources than is needed to comply with the SES by 2020.
- The pure economic analysis results not considering externalities indicated that system costs increased by the acquisition of this portfolio;
- Incorporating a value for carbon shows system benefits are higher than costs. However, there is no evidence suggesting that acquiring this Portfolio was more cost effective than other resources in terms of environmental benefits;

- In fact, the then recent experience with Xcel Energy's Border Winds project suggested that similarly sized wind acquisitions provided system benefits on a pure economic basis and far more significant benefits than the Solar PPA when the carbon value was monetized;
- The ITC benefit did not result in changing the economics from a system cost to a system benefit. Further, based on the experience with wind technological advancements coupled with the IHS market report, there was good reason to delay acquisition beyond a total of 187 MW of solar resources;
- Xcel Energy did not provide evidence in testimony that the Solar PPA portfolio is more effective in acting as a hedge for natural gas price volatility compared to other options. Further, the intermittency of solar resources actually may create the demand for natural gas fired generation for back up purposes.

Q. Based on your evaluation discussed above, can the acquisition of the Solar PPA Portfolio be considered prudent or reasonable?

A. No.

Q. **Does this conclude your testimony?**

A. Yes, this concludes my written testimony. I would like the opportunity to supplement my written testimony with oral testimony at the hearing to respond to Xcel Energy's rebuttal testimony and responses to discovery.