

Rebuttal Testimony and Schedules  
Kurtis J. Haeger

Before the North Dakota Public Service Commission  
State of North Dakota

In the Matter of the Application of Northern States Power Company for an  
Advance Determination of Prudence for a 187 MW Portfolio of Utility Scale Solar  
Resources

Case No. PU-14-810  
Exhibit\_\_\_(KJH-2)

**Rebuttal Testimony**

April 17, 2015

## TABLE OF CONTENTS

I.	Introduction and Summary	1
II.	Resource Planning Overview	3
III.	Reliance on MISO	9
IV.	Prudence of Resource Additions	20
V.	Policy Considerations	22
VI.	Changes to PPAs	36

### Schedules

Direct Testimony of Kurtis J. Haeger in the Geronimo Solar PPA Proceeding, Feb. 13, 2015	Schedule 1
Letter Agreements Between the Company and the PPA Developers	Schedule 2

1 **I. INTRODUCTION AND SUMMARY**

2  
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Kurtis J. Haeger. I am the Managing Director of Resource  
5 Planning for Xcel Energy Services Inc. (XES), the service company subsidiary  
6 of Xcel Energy Inc. In that role I coordinate the resource planning function  
7 for Northern States Power Company-Minnesota (NSP, Xcel Energy or the  
8 Company).

9  
10 Q. HAVE YOU PROVIDED OTHER TESTIMONY ON THE TOPICS YOU ARE  
11 PROVIDING HERE?

12 A. Yes. On November 7, 2014, I submitted prefiled written Direct Testimony in  
13 this proceeding. That testimony provided the Commission with the  
14 Company's view of the resource planning context that supports granting an  
15 Advance Determination of Prudence (ADP) for this requested 187 MW solar  
16 portfolio resource addition.

17  
18 I also submitted prefiled written Direct Testimony on February 13, 2015 in  
19 Case No. PU-15-095 (the Geronimo Solar PPA proceeding). My testimony in  
20 the Geronimo Solar PPA proceeding provides additional information about  
21 the Company's resource planning efforts and describes NSP's views on the  
22 desirability to plan conservatively to ensure sufficient generating capacity is  
23 and reasonable-cost energy in place to meet our customers' needs under all  
24 reasonable circumstances. In addition, that testimony provides discussion  
25 about the generation resource "Restack" concept, which arose in our  
26 settlement of the last rate case (Case No. PU-12-813) and which is currently  
27 being negotiated by the Company and Commission Staff.

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Many of the issues addressed in my Direct Testimony in the Geronimo Solar PPA case are similar to the issues raised in this case. As a result, I have attached a copy of the public version my Direct Testimony (without Schedules) in that case as, Schedule 1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Direct Testimony of Commission Advocacy Staff member Mike Diller. Mr. Diller provides an important and valid perspective for the Commission to consider in planning for system additions in a multi-jurisdictional utility like the Company. Mr. Diller’s testimony is helpful in that it provides a reasoned policy perspective on the timing and justification for the Company’s resource additions to serve our North Dakota customers. However, that policy perspective carries with it certain implications and risks that should also be taken into account as the Commission considers the appropriate timing for adding resources under the circumstances.

My Rebuttal Testimony provides the Company’s perspective on the issues raised by Mr. Diller. More specifically, I address the following:

- General resource planning concepts that influence the selection and timing of resource additions;
- The development and utilization of a planning reserve margin;
- The risks associated with reliance upon MISO as a backstop in the event of a capacity shortfall;
- The Company’s need for additional resources at this time in light of current demand forecasts;
- The potential impact on NSP’s integrated system arising from differing

1 public policy choices in the states we serve; and

- 2 • The implications if North Dakota chooses to have capacity direct-  
3 assigned to the jurisdiction rather than accept a pro-rata allocated share  
4 of the Company's integrated generation fleet.

5  
6 My testimony also presents letter agreements for minor changes to the PPAs  
7 for the 187 MW solar portfolio.

8  
9 Q. MR. DILLER SUMMARIZES HIS TESTIMONY WITH THE FOLLOWING CONCLUSION  
10 (PAGE 1:20-26):

11 “NSP’s North Dakota ratepayers do not need the proposed SP for  
12 generation capacity or the energy that these units would provide. The  
13 proposal does not represent least cost planning. Instead, the SP is being  
14 proposed to satisfy Minnesota’s Solar Energy Standard (SES). Staff  
15 recommends that the NDPSC deny the requested ADP and also deny  
16 any replacement costs for the denied capacity.” (Emphasis added.)

17  
18 HOW DO YOU RESPOND?

19 A. Mr. Diller’s summary touches on four important policy issues that I will  
20 address below. They are: (1) the timing and cost of generation additions to  
21 meet customer needs, (2) the relevant considerations and criteria (including  
22 least-cost planning principles) in selecting resources, (3) divergent state  
23 policies and the implications of those policies on a multi-state system, and (4)  
24 the implications and risks of direct-assigning generation to North Dakota.

25  
26 **II. RESOURCE PLANNING OVERVIEW**

27  
28 Q. WHY ARE YOU PROVIDING AN OVERVIEW OF RESOURCE PLANNING IN YOUR  
29 TESTIMONY?

30 A. Mr. Diller’s Direct Testimony raises important issues that are central to

1 integrated resource planning and the Company's obligation to provide safe,  
2 reliable and adequate service to our customers under all reasonable  
3 circumstances. I think it is important for the Company to provide  
4 background and context on these issues to assist the Commission in  
5 considering the policy implications of Mr. Diller's proposed approach.

6  
7 Q. PLEASE SUMMARIZE HOW THE COMPANY PLANS TO MEET ITS OBLIGATIONS.

8 A. Public utilities such as the Company have an obligation to serve all of the  
9 needs of all customers in their service areas. This obligation to serve requires  
10 that we provide for our customers' electric needs under all reasonable  
11 circumstances.

12  
13 The obligation to serve leads to the utility planning its system to ensure  
14 sufficient generating capacity is available to meet customer requirements. In  
15 order to avoid the risk of falling short, we must plan for a future that has  
16 many unknowns. Realizing that new generation usually takes several years to  
17 develop – including planning and design, obtaining regulatory approvals,  
18 procuring transmission access and fuel supply, and of course the actual,  
19 physical construction – utilities generally must initiate the generation  
20 development process three to six years before the resource is needed. The  
21 future can look very different from what we expect today. The need to  
22 accommodate future uncertainties requires a utility to plan conservatively and  
23 ensure that adequate power supply exists even if unforeseen circumstances  
24 arise.

25  
26 Q. WHAT DETERMINES WHETHER THE COMPANY NEEDS TO ADD GENERATION?

1 The Company has two major objectives when it considers whether to add new  
2 resources to the integrated system:

- 3 • Reliably serve customers during those hours when their needs are  
4 highest; and
- 5 • Minimize total system energy costs throughout the year, taking into  
6 account all relevant considerations.

7  
8 To meet these twin goals, the Company considers both the need to meet our  
9 peak demand and our overall energy mix. There is more than one  
10 combination of resource types that can be employed to meet a given system's  
11 peak demand. And there is a variety of energy sources that can contribute to  
12 our mix.

13  
14 Q. IS IT APPROPRIATE TO ONLY CONSIDER THE COMPANY'S CURRENT DEMAND  
15 FORECASTS WHEN DECIDING WHETHER TO ADD RESOURCES TO THE SYSTEM?

16 A. I agree that assessing and planning for the current forecast of peak demand is  
17 a critical consideration, but it is not the only criterion in our determination of  
18 what resources to add to the system. The Company must consider both the  
19 need to reliably serve our customers under all reasonable circumstances and to  
20 achieve a low-cost overall energy mix for our integrated system while meeting  
21 the policy requirements of all of the states we serve.

22  
23 As a result, in planning resource additions, we take into account (1) peak  
24 demand, (2) reserve margin requirements, (3) contingencies such as higher-  
25 than-anticipated peak demand or forced (unplanned) outages, (4) energy mix  
26 (and overall energy costs), and (5) relevant policy considerations.

27

1 Q. WHY DOES THE COMPANY NOT PLAN NEW GENERATION TO PRECISELY MATCH  
2 FORECAST PEAK DEMAND?

3 A. The Company makes its resource investments within a long-term planning  
4 horizon – 40 years or more. It is not plausible to precisely match generating  
5 capacity with the exact customer demands in each year, keeping in mind that it  
6 is not acceptable to be short in any one year. We take a comprehensive  
7 approach to planning how we will serve all customers reliably throughout the  
8 planning horizon considering all circumstances.

9

10 Q. WHAT DO YOU MEAN BY A COMPREHENSIVE APPROACH TO PLANNING?

11 A. Several variables are considered. We consider (1) the size or amount of  
12 capacity to be added to the system including consideration of economies of  
13 scale, (2) the type of resource selected, such as natural gas or renewable  
14 resources, (3) the timing of the selection to ensure that we meet all of our  
15 obligations, and (4) whether there is firm delivery from the new generation site  
16 to the Company's customers.

17

18 For example, it is commonly known that the least expensive option for adding  
19 capacity is to build combustion turbines to serve as peaking plants. Yet, most  
20 utilities also plan for and build intermediate and baseload plants and add  
21 renewable energy to their systems – even at a much higher capital cost per  
22 MW than a peaking unit – to balance the energy needs of the customers they  
23 must serve. Utility planners understand that baseload plants and renewable  
24 energy resources are more expensive to build, but their energy production  
25 costs are relatively low.

26

27 Seeking to obtain an appropriate mix of baseload, intermediate, and peaking

1 facilities helps to balance the costs of capacity and energy and obtain a diverse  
2 resource mix for the utility. A diverse resource mix, in turn, allows us to meet  
3 a wide range of needs from round-the-clock baseload energy to immediate  
4 peaking needs. A well-balanced generation portfolio provides a versatile and  
5 robust ability for a utility to respond to its customers' changing needs.

6  
7 Q. WHAT ARE THE FACTORS THAT YOU CONSIDER WHEN DECIDING WHETHER  
8 AND WHEN TO INSTALL NEW GENERATION SUCH AS THE 187 MW SOLAR  
9 PORTFOLIO THAT IS THE SUBJECT OF THIS CASE?

10 A. First, new generation resources, including those that are the subject of this  
11 proceeding, require significant investment and time to build. We make  
12 generation resource decisions taking into account that we need to have  
13 enough time to deploy the generation resource to meet the identified  
14 customer need. This can be a challenge, since the development and  
15 construction cycle take up to five or more years during which time our  
16 demand forecasts could change dramatically (either up or down).

17  
18 Second, economics generally favor building generation in fewer, but larger,  
19 capacity increments to capture economies of scale and to minimize duplicative  
20 infrastructure. This dynamic can result in choosing generation resources that  
21 exceed the immediate minimum forecast demand level by some amount to  
22 capture the benefits of the larger increment (*i.e.*, scale, efficiency, margins).  
23 Constructing larger increments of generation will also influence the timing of  
24 the next generation resource since, once built, a generation resource remains  
25 available to meet increasing demand, thereby deferring the addition of the  
26 next generation resource.

27

1 All of these factors tend to favor having a conservative amount of generation  
2 on the system going forward than what a simple analysis of the expected  
3 demand and the existing resources may suggest.

4  
5 Q. DOES THE UTILITY PLAN ITS SYSTEM IN ISOLATION FROM OTHER UTILITIES?

6 A. In some ways yes, and in some ways, no.

7  
8 On one end of the spectrum, a utility is ultimately responsible for ensuring  
9 that they will have adequate resource to meet its customers' needs. Therefore,  
10 utilities must do their own system planning, utilizing their own resource  
11 planning criteria, which is influenced by their obligations and regulatory  
12 oversight.

13  
14 On the other end of the spectrum, planning paradigms have always taken into  
15 account the efficiencies achieved through interconnected operations with  
16 other interconnected utility systems. For example, when the Company was a  
17 member of the Mid-Continent Area Power Pool (MAPP), the ability to utilize  
18 other systems to ensure adequate capacity, and the MAPP requirements in this  
19 respect, were a key part of our resource planning considerations. Similarly,  
20 with the advent of MISO, the MISO reserve margin requirements are also a  
21 key consideration in our resource planning. Regional coordination enables all  
22 participating utility systems to meet reliability standards which lower reserve  
23 margins, than if each system operated on its own.

24  
25 I stress, however, that the existence of other systems to support our resource  
26 adequacy does not fully compensate for the need to ensure we have sufficient  
27 capacity available on our system to meet our customers' needs. While regional

1 constructs, such as MISO, can be helpful, I do not believe it is prudent to rely  
2 on MISO to ensure adequate resources are available should conditions change.

3  
4 **III. RELIANCE ON MISO**

5  
6 Q. MR. DILLER TESTIFIES ON PAGE 3:8-14:

7 “The structure of generation resource adequacy has changed under  
8 regional grid operators like the one NSP belongs to; Midcontinent  
9 Independent System Operator (MISO). One of the primary values of  
10 operating the electric system on a regional basis is to share generation  
11 assets to enable companies to carry a smaller reserve margin and  
12 improve reliability at the same time. It is no longer necessary or  
13 desirable for every utility to carry large amounts of excess generation as  
14 though they are still operated on a stand-alone basis.”

15  
16 HOW DO YOU RESPOND?

17 A. Mr. Diller is correct that regional operation such as under MISO may enable  
18 utility systems to carry smaller reserve margins than if they each operated on  
19 their own. He is also correct that MISO recently began operating a voluntary  
20 capacity auction that provides a small amount of short-term capacity to  
21 utilities for balancing their systems.

22  
23 That said, I have some concerns with Mr. Diller’s conclusion. Specifically, his  
24 position with respect to MISO does not fully consider all of the factors that  
25 must be taken into account when planning for future resource additions.  
26 These concerns relate mainly to MISO’s resource adequacy requirements and  
27 the related planning reserve margin as well as the feasibility of relying on  
28 MISO’s voluntary capacity auction. Fundamentally, we believe that  
29 participation in MISO does not remove our need to ensure that we have  
30 enough capacity resources for our own NSP System.

1           **A.       MISO Resource Adequacy Requirements**

2    Q.   WHAT IS THE PURPOSE OF A PLANNING RESERVE MARGIN WITH RESPECT TO  
3       RESOURCE ADEQUACY?

4    A.   The planning reserve margin represents additional generation capacity, over  
5       and above the utility’s forecast of its customers’ demand needs. Thus, the  
6       planning reserve margin is forward looking and based on the utility’s  
7       forecasted demand. To illustrate, if a utility has 100 MW of forecasted  
8       demand and it requires 7 percent of reserve margin, it must have 107 MW of  
9       capacity.

10  
11       The excess capacity required by the reserve margin is intended to  
12       accommodate operational fluctuations that occur throughout the year. In  
13       essence, the reserve margin is intended to ensure sufficient capacity is available  
14       to account for variations in the actual levels of demand as well as resource  
15       availability on peak days, as compared to the levels assumed in the forecast  
16       modeling. In this way, the reserve margin ensures that capacity is available to  
17       address the fundamental difference between forecasting and actual operations.

18  
19       For example, our demand forecasts are weather normalized and so the reserve  
20       margin accounts for the actual variations in weather that we know will occur.  
21       As another example, our forecasts assume that our generating resources will  
22       be operating under normal conditions; the reserve margin provides a cushion  
23       for outages and derates that can affect the actual amount of generation  
24       available on any given day.

25  
26       However, our demand forecasts are also keyed off of key economic indicators  
27       and other, non-operational, assumptions to determine our forecasted amount

1 of customer demand. For example, we utilize econometric data such as  
2 housing starts and gross domestic product in building our demand forecasts.  
3 We also make assumptions about customer usage patterns and technological  
4 factors than can impact customer demand. Since the reserve margin does not  
5 take into account these non-operational factors and therefore is not designed  
6 to compensate for changes to these factors, should these non-operational  
7 assumptions prove to be incorrect, it is likely the reserve margin will not be  
8 sufficient to ensure that sufficient capacity is available to meet customer  
9 demand.

10  
11 As described in my testimony in Case No. PU-15-095 (provided as Schedule  
12 1), the Company has seen a fluctuation in its demand forecasts due to these  
13 non-operational metrics that argue for conservative resource planning  
14 notwithstanding the availability of a reserve margin.

15  
16 Q. DOES THIS MEAN THAT YOU DO NOT AGREE THAT THE COMPANY SHOULD  
17 ONLY PLAN TO MEET ITS DEMAND FORECAST PLUS A RESERVE MARGIN?

18 A. Correct. The planning reserve margin has limits; it does not take into account  
19 that demand forecasts can shift dramatically in the four to six year period that  
20 it may take to develop or arrange for additional generation resources.  
21 Economic factors and historical usage are two of the more significant forecast  
22 variables, and the uncertainty in these variables since the 2008/2009 recession  
23 has been significant.

24  
25 That is why we believe it is appropriate to take a conservative approach in  
26 resource planning by accounting for these variables that are not adequately  
27 captured by a planning reserve margin.

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Q. DO YOU CONCUR WITH MR. DILLER THAT MISO’S PLANNING RESERVE MARGIN REQUIREMENTS ARE LIKELY TO DECLINE IN THE FUTURE?

A. It’s difficult to say what the future holds for MISO’s reserve margin requirements. MISO’s reserve margin calculations are based on a series of assumptions. Under a certain set of assumptions, MISO forecasts that the current 7.1 percent planning reserve margin could decline to 6.6 percent in 2024. However, this result reflects assumptions that there will be significantly more generation added to the MISO system by 2024 and that these future resources will be more reliable than existing generation. However, given the uncertainty surrounding the utility industry and changes in generation technology, MISO concluded that a more likely outcome is that the reserve margin will stay relatively flat.

When we couple the changing industry with the potential of retiring a significant number of large baseload plants in the next several years, it is clear that the future need for new generation is very difficult to predict. It is my opinion that this uncertainty argues for a more conservative planning approach now.

**B. MISO Voluntary Capacity Auction**

Q. DO UTILITIES BUY AND SELL CAPACITY WITH EACH OTHER TO BALANCE THEIR NEEDS?

A. Yes. Historically, utilities have used bilateral agreements to buy and sell both short-term and long-term capacity and energy to each other. In addition to the traditional option of bilateral agreements, MISO has developed a voluntary short-term capacity auction as an option for utilities to use.

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Q. DO YOU AGREE WITH MR. DILLER’S CONCLUSION THAT THE AVAILABILITY OF BALANCING CAPACITY THROUGH MISO PRECLUDES THE NEED FOR NSP TO PLAN FOR AND OBTAIN CAPACITY FOR ITS CUSTOMERS?

A. No. While MISO’s efforts have been beneficial to customers, the short-term voluntary capacity auction administered by MISO is not an effective tool to replace traditional, single-system resource planning efforts. Utilities have typically accomplished the same outcome through bilateral transactions. Therefore, MISO’s voluntary capacity auction merely provides another option for utilities to consider on a short-term basis only.

Q. IS IT PRUDENT FOR UTILITIES TO RELY ON MISO’S VOLUNTARY CAPACITY AUCTION TO BACKSTOP ANY RESOURCE DEFICIENCIES?

A. I do not believe so. The same factors that could contribute to a longer-term capacity deficit for a utility are likely to also lead to an absence of available capacity in the MISO voluntary capacity auction. Therefore, prudent resource planning would ensure that a utility’s system has sufficient resources under all circumstances, notwithstanding the availability of a balancing mechanism such as the MISO voluntary capacity auction.

Q. PLEASE ELABORATE.

A. Fundamentally, it is only prudent to rely on MISO’s voluntary capacity auction if we can be assured that sufficient capacity will be available in the MISO region when we need it. I do not believe that the current structure of MISO’s voluntary capacity auction can provide such guarantees; let alone ensure that we can obtain the capacity at a reasonable price.

1 On the demand side, since a large portion of the capacity on a utility's system  
2 is driven by historical usage and economic factors, there is a high probability  
3 that when these key indicators change the customer demand on any one  
4 utility's system, they will also be changing the demand requirements of the  
5 other utilities within MISO. Thus, the capacity needed to support one utility's  
6 deficiency may likely be needed to support another utility's deficiency.  
7 Without a buffer of additional capacity above a utility's planning reserve  
8 margin, there is no guarantee that capacity will be available when it is needed.

9  
10 Q. IS THE SAME THING TRUE ON THE SUPPLY SIDE?

11 A. Yes, the same is true on the supply side. With implementation of existing  
12 environmental regulations (*e.g.*, Mercury and Air Toxics Standards, Cross-State  
13 Air Pollution Rule) or potentially new regulations (*e.g.*, Clean Power Plan),  
14 there is a high likelihood that the economics of keeping existing power plants  
15 open will be adversely impacted, which could result in retirements. These  
16 retirements are likely to happen simultaneously across many utilities. The  
17 potential for significant future power plant retirements within a relatively short  
18 period of time could constrain available capacity when it is most needed.

19  
20 Again, this uncertainty would suggest that MISO's voluntary capacity auction  
21 may have use as a backstop tool only, but not as a prudent resource to rely on  
22 to meet capacity needs. And relying on other utilities with excess generation  
23 to meet the Company's capacity needs could lead to unforeseen capacity  
24 deficiencies in the future.

25  
26 **C. Other Considerations**

27 Q. MR. DILLER POINTS OUT THAT MISO HAS A VERY LARGE FOOTPRINT,

1 INCLUDES SIGNIFICANT CAPACITY, AND PROVIDES ECONOMIES OF SCALE TO  
2 ITS MEMBERS. SHOULDN'T THIS HELP MITIGATE THE ISSUES YOU JUST  
3 DESCRIBED?

4 A. I generally agree with Mr. Diller that MISO provides these significant benefits  
5 to its members in the region. Through its roles as regional transmission  
6 provider and operating the regional energy market, MISO provides valuable  
7 coordination to the regional marketplace. Further, MISO's large footprint,  
8 and continual transmission planning efforts to reduce congestion on the  
9 MISO system, provide significant benefits to knit the MISO system together  
10 and provide outlet for location-based (*i.e.*, wind) generation for the entire  
11 MISO system.

12  
13 However, the MISO footprint is split up into nine Local Resource Zones  
14 (LRZ). The transmission connections between each LRZ may not be  
15 sufficiently robust to allow for capacity to be shared amongst zones for  
16 resource adequacy purposes. To account for this, MISO has included a  
17 "Local Clearing Requirement" in its resource adequacy rules, which  
18 determines the amount of resources which must be located in a utility's LRZ  
19 so that it can meet its resource adequacy requirements.

20  
21 Therefore, in reality, the Company must mainly rely (with a few exceptions)  
22 on the resources available in LRZ 1, which is where the NSP System is  
23 located. Having to rely on a single LRZ for capacity sharing significantly  
24 mitigates the economies of scale and geographic breadth of MISO for  
25 resource adequacy purposes. I note that the resource additions for which we  
26 are requesting an ADP have added value because they reside within LRZ 1.

27

1 I believe Mr. Diller’s assessment overstates the usefulness of MISO’s  
2 voluntary capacity market for resource adequacy purposes. In order for there  
3 to be sufficient capacity available in the MISO voluntary capacity auction that  
4 can be used for the NSP System, other utilities within LRZ 1 will need to have  
5 installed sufficient excess capacity to make up any shortfall the Company may  
6 have. If all utilities only planned to their reserve margin there would not be  
7 significant amounts of available capacity for the Company to use. Further, as  
8 the largest system in LRZ 1, the use of excess capacity provided by the fact  
9 that capacity additions are “lumpy” in nature could be insufficient for the  
10 Company to use.

11  
12 To underscore the fact that reliance on MISO’s voluntary capacity auction  
13 could result in a capacity shortfall, I note that MISO’s capacity auction is held  
14 only about two months prior to the start of the applicable planning year. So,  
15 if the auction fails to supply needed capacity, there is essentially no time  
16 afterwards to correct the deficiency.

17  
18 Q. MR. DILLER ACKNOWLEDGES ON PAGE 6:20-28 THAT THE COMPANY CAN  
19 INCUR SIGNIFICANT PENALTIES FOR FAILURE TO PLAN FOR ADEQUATE  
20 GENERATION TO COVER OUR PEAK DEMAND AND REQUIRED RESERVE  
21 MARGINS. HOW WOULD YOU RESPOND?

22 A. I agree that the potential for penalties is both real and substantial. However, I  
23 take issue with his apparent conclusion that it would be prudent to rely on  
24 purchasing short-term capacity to cover any potential shortfall that may arise.

25  
26 Ultimately, MISO is not designed or intended to supplant the utility’s  
27 traditional resource planning function nor the Commission’s oversight and

1 approval of generation resource selections. MISO's key responsibility is  
2 regional reliability. It implements its tariff on behalf of all stakeholders  
3 throughout the large MISO footprint. In fulfilling its functions, MISO's focus  
4 is properly on regional issues, rather than state- or utility-specific concerns.

5  
6 Q. ARE THERE OTHER FACTORS THAT THE COMMISSION SHOULD TAKE INTO  
7 CONSIDERATION?

8 A. Yes. As we described in great detail in our Resource Plan in Case No. PU-15-  
9 019, the utility industry and the NSP System are in a period of uncertainty and  
10 evolution. The utility industry as a whole will be impacted by the  
11 implementation of existing and new environmental regulations. Further, the  
12 NSP System may need to replace more than seventy-five percent of its energy  
13 resources by 2035. While it is likely that it will take years for these issues to be  
14 fully resolved, we must act in a very short timeframe to ensure we have  
15 adequate resources in place from 2016 to the early 2020s.

16  
17 Q. PLEASE DESCRIBE THE IMPACT THAT MISO-WIDE CAPACITY RETIREMENTS  
18 THAT ARE CURRENTLY CONTEMPLATED BY THE COMPANY AND OTHER MISO  
19 UTILITIES WILL LIKELY HAVE ON THE PRUDENCE OF MAKING A RESOURCE  
20 ADDITION AT THIS TIME.

21 A. Our analyses indicate that the cost of generation development, especially  
22 natural gas-fired generation, may become more expensive as demand for new  
23 natural gas-fired generation increases due to the decommissioning of coal  
24 plants in the MISO footprint. And, as mentioned, these plant retirements are  
25 also expected to increase the costs of short-term capacity in MISO's voluntary  
26 capacity auction. Taking a conservative approach with diversified energy  
27 resources such as the solar resource additions that are the basis of this

1 proceeding will position the Company well for the long term in light of these  
2 issues.

3  
4 Q. ON PAGE 5:8-24, MR. DILLER DESCRIBES SOME POTENTIAL IMPACTS OF  
5 HAVING EXCESS GENERATION IN THE MISO REGION. HOW DO YOU  
6 RESPOND?

7 A. The Company appreciates Mr. Diller's discussion on this issue. However, I  
8 believe the situation is more complicated.

9  
10 It is important to distinguish between recovery of production (energy) costs  
11 and recovery of capacity costs. Under MISO's current rules, we may only  
12 include our production costs when we offer generation into the market.  
13 Therefore, the energy markets only allow us to recover the marginal cost of  
14 producing the energy. In contrast, we recover our capacity costs by including  
15 our assets in rate base and recovering these investments through retail  
16 revenues, or, in the case of merchant generation, through bilateral contracts  
17 for the capacity.

18  
19 When planning a utility system, one must plan for an optimal mix of energy  
20 and capacity. In certain circumstances, the overall least-cost method of  
21 providing energy and capacity to meet demand requirements is to install low-  
22 cost capacity generation (*e.g.*, combustion turbines) that is not expected to run  
23 often because of the high production costs to make this energy. The primary  
24 purpose of this low-cost capacity is to ensure that there are adequate resources  
25 available to meet peak demands; the energy value of that resource is of  
26 secondary importance. Therefore, this resource has value to the system by  
27 providing low-cost capacity since the system needs do not require the energy

1 from this resource to meet demand needs except for a very few hours during  
2 the year.

3  
4 It is rather complicated to identify the impact of a particular resource on  
5 energy prices in the market. The peaking resource I mention above would  
6 have little effect on energy pricing since it is designed to provide energy only  
7 during limited hours of the year. Whereas an intermediate resource would  
8 have more effect on the cost of energy since it is designed to produce more  
9 energy when there are needs above what can be met by regular baseload  
10 generation. This analysis becomes even more complicated when the impact of  
11 intermittent resources such as solar and wind are taken into account.

12  
13 Q. PLEASE SUMMARIZE YOUR COMMENTS ON THIS MATTER.

14 A. The interplay of the types of resources on the system, their effect on energy  
15 pricing, and the carrying costs of capacity are what ultimately effects overall  
16 costs to our customers. In certain circumstances we may have the opportunity  
17 to add resources to our system that lower the overall costs of power to our  
18 customers by reducing energy prices by more than the incremental increase in  
19 capacity costs. This is the rationale behind most baseload power plants but  
20 also was the underlying economic justification for adding the Pleasant Valley  
21 and Border Winds projects to the NSP System. Although these resources  
22 added investments to rate base, these costs were offset by zero cost energy,  
23 thereby bringing down total system costs to our customers over their life.

24

1 **IV. PRUDENCE OF RESOURCE ADDITION**

2  
3 Q. MR. DILLER STATES ON PAGE 2:2-4 THAT INCREMENTAL NEW CAPACITY IS NOT  
4 NEEDED ON THE NSP SYSTEM AT THIS TIME. HOW DO YOU RESPOND?

5 A. I agree that our most recent demand forecast shows that we have sufficient  
6 capacity to serve our integrated system until 2024 without considering other  
7 issues. However, as I describe above, (1) we believe it is appropriate to plan  
8 conservatively to ensure we have resources available in case we experience an  
9 unexpected increase in demand, (2) obtaining the bare minimum of capacity to  
10 serve our peak-hour demand is not the only consideration that goes into  
11 deciding to add resources, and (3) we have other reasons to add solar capacity  
12 at this time, including the need to satisfy Minnesota’s Solar Energy Standard.  
13 On balance, we conclude that the overall needs of our integrated system are  
14 better served by adding the 187 MW solar portfolio at this time.

15  
16 Q. ARE THERE OTHER CIRCUMSTANCES THAT WOULD ALSO SUPPORT THE  
17 PRUDENCE OF MAKING RESOURCE ADDITIONS TO THE SYSTEM NOW?

18 A. Yes. Even beyond preparing to supply customer demand if growth increases  
19 faster than presently forecasted, adding solar generation at this time is an  
20 appropriate choice under the circumstances. Those circumstances include:  
21 (1) anticipated MISO-wide capacity retirements; (2) the currently-favorable  
22 interest rate and cost environment for solar generation; (3) an uncertain  
23 environmental regulatory environment and the likelihood that regulations will  
24 increasingly focus on carbon-free generation; and (4) our need to meet the  
25 Solar Energy Standard of the State of Minnesota.

26

1 Q. MR. DILLER SAYS THAT THE 187 MW SOLAR PORTFOLIO IS NOT A “LEAST-  
2 COST” RESOURCE. HOW DO YOU RESPOND?

3 A. Mr. Diller’s observation is correct when looked at from one perspective, but it  
4 does not fully address all of the considerations we include in development and  
5 selection of resources. Let me explain:

6

7 I would agree that on a per-kWh basis, solar capacity and energy is not least-  
8 cost when compared to natural gas generation or even wind generation.  
9 However, when we make resource decisions, I do not believe the unit cost of  
10 a resource can be considered in isolation. For example, prudent resource  
11 planning would take into account policy drivers for a particular resource  
12 addition; market conditions which impact the cost of the generation in  
13 comparison to potential future costs; future system retirements; and resource  
14 diversity.

15

16 Mr. Diller does not explain what he is measuring against when he concludes  
17 the 187 MW solar portfolio is not least-cost. Given the Solar Energy Standard  
18 compliance obligation in Minnesota, I believe the most appropriate  
19 comparison is to consider the cost of this solar portfolio with the cost of  
20 similar solar projects that were available to us at the time we made this  
21 selection. As we describe in our filing, the three solar resources being  
22 considered in this case were selected because they were the least-cost solar  
23 resources that met the requirements of the competitive request for proposal  
24 (RFP) that we conducted.

25

26 Q. MR. DILLER SUGGESTS THAT LESS EXPENSIVE RESOURCE OPTIONS ARE  
27 AVAILABLE TO THE COMPANY. HOW DO YOU RESPOND?

1 A. As I mention above, I agree that the nominal cost of natural gas and wind  
2 generation is less than solar on a per kWh basis. But it is also important to  
3 consider other factors, such as the ones I described above.

4  
5 I note that our resource plan contemplates significant additional solar  
6 generation during the planning horizon. Thus adding solar to the system now  
7 is appropriate in light of the overall circumstances. I also note that solar  
8 generation, while intermittent in nature, is generally producing energy during  
9 the peak periods of the day. This means that solar generation is available to  
10 offset high peak energy market pricing. This is in contrast to wind generation  
11 which is more likely to experience intermittent output primarily during non-  
12 peak periods.

## 13 14 **V. POLICY CONSIDERATIONS**

### 15 16 **A. Multi-State Considerations**

17 Q. YOU MENTIONED THAT ONE OF THE REASONS FOR SELECTING SOLAR  
18 RESOURCES AT THIS TIME IS THE NEED FOR THE COMPANY TO COMPLY WITH  
19 MINNESOTA'S SOLAR ENERGY STANDARD. IS NORTH DAKOTA REQUIRED TO  
20 FOLLOW MINNESOTA'S ENERGY POLICY AS IT PERTAINS TO SOLAR ENERGY?

21 A. No. North Dakota is free to implement its own state energy policies.

22  
23 I agree with Mr. Diller's observation on page 8:5-10 of his testimony that  
24 North Dakota and Minnesota "should seek to mutually and beneficially  
25 coexist whenever possible so long as doing so is not detrimental to our own  
26 citizenry." However, there is more to consider in the determination of

1 “detrimental” than simply whether the resource addresses a policy  
2 requirement in another state.

3  
4 Q. PLEASE EXPLAIN.

5 A. The Company jointly plans for and operates an integrated system that serves  
6 more than 1.8 million retail electric customers in Michigan, Minnesota, North  
7 Dakota, South Dakota, and Wisconsin. We have successfully planned for and  
8 managed the integrated NSP System to meet all of our customers’ needs for  
9 almost 100 years. Because customers in all of our states are served by the  
10 same system, we have been able to achieve significant economies of scale that  
11 provide benefits to all of our customers in all of the states we serve.

12  
13 Q. CAN THE COMPANY ACCOMMODATE ALL OF THE ENERGY POLICIES OF ALL OF  
14 ITS STATES?

15 A. The simple fact is that Xcel Energy is *required* to comply with the energy  
16 policies of all of the states in which we provide service, and we are constrained  
17 by the regulatory processes prescribed by lawmakers and regulators in each  
18 state. We are finding it increasingly difficult to accommodate all of the various  
19 policies, as each state in which we provide electric service has different  
20 regulatory constructs and oversight regimes. However, we continue to believe  
21 that the benefits of our large integrated system outweigh the costs that may be  
22 imposed by any particular state.

23  
24 Q. HOW DOES THE COMPANY ACCOMMODATE THE INTERESTS OF DIVERGENT  
25 STATE POLICIES IN MAKING RESOURCE CHOICES?

26 A. In making resource choices we take into account existing and evolving  
27 environmental regulations; state public policy choices from each of our

1 jurisdictions; changing customer expectations; the condition of our existing  
2 generation fleet, which is aging and will require significant change in the  
3 coming years; and emerging technologies that change the way energy is  
4 generated and delivered. This multifaceted set of issues sometimes means that  
5 we may choose a resource to meet state policy goals in an amount greater than  
6 what our forecast might suggest, particularly in a circumstance where we have  
7 experienced forecast volatility and/or impending loss of significant cost  
8 reduction incentives.

9  
10 Q. WHAT SHOULD THE COMMISSION CONSIDER IN DECIDING WHETHER NSP'S  
11 RESOURCE DECISIONS ARE "DETRIMENTAL TO OUR OWN CITIZENRY" AS  
12 SUGGESTED BY MR. DILLER?

13 A. The Company believes it is important for the Commission to consider a broad  
14 range of factors including the interests of North Dakota customers as a whole,  
15 rather than focusing on any particular consideration. In other words, when  
16 viewing our resource choices with respect to our North Dakota customers, it  
17 is important to balance the cost impact of meeting certain non-North Dakota  
18 energy policy requirements with the economies of scale, and therefore lower  
19 costs, provided by the large demand from the other states in the NSP System.  
20 Even if the Company makes resource acquisitions in part to accommodate  
21 Minnesota's energy policies, it does not necessarily mean that our overall  
22 integrated resource mix is not in the best interest of all of our customers.

23  
24 Q. PLEASE EXPLAIN.

25 A. What I mean by this is that the North Dakota citizenry experiences a variety  
26 of costs and benefits in being served by NSP's integrated five-state system.  
27 For example, our North Dakota customers are able to take advantage of their

1 pro rata share of the Company's extensive nuclear, coal, natural gas and large  
2 hydro generation. These resources, which provide low-cost and efficient  
3 generation, would likely not be as available to our North Dakota customers if  
4 our North Dakota operation was a stand-alone system. This is because having  
5 the scope and scale of the other ninety-five percent of the NSP System allows  
6 the Company to obtain the critical mass to achieve significant economies of  
7 scale.

8  
9 The Commission has historically approved the North Dakota share of the  
10 Company's resource choices, including even wind and biomass additions to  
11 the system. While many of those resources were added in furtherance of  
12 Minnesota energy policy, our North Dakota customers benefited overall from  
13 the integrated system while accepting the costs of those policy choices. In  
14 addition to the low-cost baseload facilities I mentioned earlier, the benefits  
15 included transmission system reliability improvements and fuel price volatility  
16 hedges from non-thermal generation additions.

17  
18 In the end, the Company believes that there is a balance to be struck between  
19 (1) the benefits of a large, multi-state system, and (2) accommodating the  
20 requirements of a particular state's energy policy.

21  
22 Q. SHOULD THE COMMISSION ALSO CONSIDER THE QUALITATIVE FACTORS OF  
23 THE COMPANY'S PROPOSED SOLAR RESOURCE ADDITIONS?

24 A. Yes. As we discuss at length in our recently filed resource plan, the utility  
25 industry and the NSP System are in a period of great change and significant  
26 uncertainty. We believe that our resource decisions during this time should be  
27 made with an eye to the future. The fuel price hedge and resource diversity

1 value of our 187 MW solar portfolio are exactly the types of considerations  
2 that the Commission should take into account while evaluating our request.  
3 The Commission has been making these types of qualitative evaluations since  
4 at least 2008<sup>1</sup> and should continue to do so.

5  
6 Q. PLEASE ELABORATE.

7 A. Our underlying purpose for making our proposed solar resource addition  
8 notwithstanding, there are material qualitative advantages of adding these  
9 resources to the NSP System at this time that argue for their prudence.

10  
11 Solar is a developing resource and making utility scale additions to the NSP  
12 System will provide us with operational experience with this type of resource.  
13 Further, solar resources provide us with a hedge against other fuels, adding to  
14 our resource diversity. These resource additions will also help to position us  
15 should future carbon regulations in fact become mandatory. This is similar to  
16 the Company's experience with wind generation. While Minnesota policy was  
17 a driver in our initial additions of wind to the system, we are now seeing wind  
18 be an economic resource that can and does provide benefits to our customers,  
19 including comparatively low cost of energy that minimizes upside fuel price  
20 risk.

21  
22 These qualitative factors are the same types of factors that the Commission  
23 has, in the past, used to recognize the prudence of renewable resource  
24 additions such as wind that were not least-cost (but were a reasonable cost for  
25 that resource type) and not utilized to meet an identified capacity deficit.<sup>2</sup>

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<sup>1</sup> See Case Nos. PU-06-481; PU-06-482.

<sup>2</sup> See, e.g. Case No. PU-08-907.

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Given the uncertain future, we believe that a qualitative evaluation of our proposed resource addition is appropriate and will further demonstrate the prudence of our resource additions at this time at a system-wide net cost of only \$14 million (compared to a total system cost of more than \$1 billion) on a present value revenue requirements basis.

**B. Restack**

Q. WHAT OPTIONS DOES THE COMMISSION HAVE IF IT DOES NOT APPROVE THE COMPANY’S REQUEST?

A. I believe there are two basic options available to the Commission: (1) allow both the capacity and energy of the 187 MW solar portfolio to be re-priced through the North Dakota Restack process, or (2) direct-assign resources to be consistent with divergent state energy policies. Each of these choices carries important policy considerations.

Q. WHAT IS THE COMPANY’S RECOMMENDATION?

A. In this circumstance, we respectfully request that the capacity and energy of any resource for which the Commission does not grant an ADP be eligible to be included in the Restack process.

Q. PLEASE SUMMARIZE THE NORTH DAKOTA RESTACK PROCESS.

A. As the Commission is aware, development of a Restack Agreement with Commission Staff is guided by ten negotiating principles adopted by the Commission in the Settlement Agreement adopted in our last rate case. Key among these principles is that both the energy and capacity costs of any new resource addition (such as those proposed by the Company here) rejected by

1 the Commission be re-priced using a suitable marginal cost proxy to essentially  
2 remove from North Dakota rates what the Commission has determined to be  
3 unacceptable policy premium costs of the resource. By addressing both the  
4 capacity and energy impacts of such resource additions, the Restack will  
5 acknowledge the “used and useful” nature of these resource additions to the  
6 NSP System while identifying and mitigating the cost impact for our North  
7 Dakota customers of energy policy decisions made in other states with which  
8 the Commission does not concur but which provide used and useful capacity  
9 and energy to the NSP System.

10  
11 The Settlement Agreement’s negotiating principles indicate that the  
12 appropriate proxy pricing would reflect the marginal cost of the next unit of  
13 capacity or energy available to be added to the system. We are currently  
14 negotiating the appropriate capacity and energy proxy pricing framework for  
15 this “marginal” cost with Commission Staff. The final Agreement will  
16 establish the “used and useful” pricing for any new resource additions subject  
17 to the Restack.

18  
19 Q. WHY DO THE RESTACK NEGOTIATING PRINCIPLES INCLUDE A PROXY PRICING  
20 FOR CAPACITY EVEN IF THERE IS NO DEMONSTRATED CAPACITY DEFICIT  
21 JUSTIFYING THE ADDITION OF A PARTICULAR RESOURCE?

22 A. As I mentioned, the Restack concept is premised on maintaining the  
23 Company’s ability to plan and operate the NSP System as an integrated system  
24 while at the same time addressing the impact of different state energy policies  
25 on our North Dakota customers. Using a proxy price for energy and capacity  
26 provides an objective standard (*i.e.* the cost of the next increment of energy or

1 capacity to the system) to determine what type of “policy premium” exists for  
2 the resource addition.

3  
4 Q. WHAT DO YOU MEAN BY THE TERM “POLICY PREMIUM?”

5 A. In this instance, Minnesota’s energy policy calls for the Company to deploy  
6 additional resources that are of certain types and sizes. The Restack provides  
7 a mechanism to quantify the additional costs of both the capacity and energy  
8 from these resources due to other states’ policy preferences. This “policy  
9 premium” provides a way to help ensure North Dakota’s rates better reflect  
10 North Dakota energy policy judgments while allowing the Company to  
11 continue to make resource decisions for the integrated system.

12  
13 Q. HOW DOES THE RESTACK CONCEPT MAINTAIN A BALANCE BETWEEN NORTH  
14 DAKOTA’S ENERGY POLICY JUDGMENTS AND THE COMPANY’S RESOURCE  
15 SELECTIONS?

16 A. By determining a proxy price for the capacity and energy, North Dakota  
17 customers are still contributing to used and useful resources on the integrated  
18 system and specifically for the energy they use and the capacity that is serving  
19 them. In this manner we are able to appropriately allocate the energy and  
20 capacity of all of the resources on the integrated NSP System to all of our  
21 customers, and thereby maintain the integrated nature of the NSP System.

22  
23 Q. If THIS 187 MW SOLAR PORTFOLIO IS NOT APPROVED BY THE COMMISSION,  
24 WHY WOULD IT BE APPROPRIATE TO INCLUDE IT IN THE RESTACK?

25 A. Yes. Should the Commission not deem our proposal prudent, we believe that  
26 including the 187 MW solar portfolio in the Restack allows us to continue to  
27 plan and operate the NSP System on an integrated basis while a long-term or

1 permanent solution to the state divergent energy policy issue is being  
2 developed.

3  
4 Q. HOW WILL THE RESTACK ALLOW THE COMPANY TO CONTINUE TO PLAN AND  
5 OPERATE THE NSP SYSTEM ON AN INTEGRATED BASIS?

6 A. The Restack provides a short- to mid-term solution to the issue of  
7 accommodating divergent state policies by pricing and excluding from North  
8 Dakota rates the “policy premium” associated with those resources. It  
9 therefore reflects an opportunity to address policy differences while at the  
10 same time providing the Company with at least partial recovery for the  
11 capacity and energy that are actually being used to serve North Dakota  
12 customers.

13  
14 Q. IF THE COMMISSION DOES NOT APPROVE THIS RESOURCE AND IT IS  
15 SUBSEQUENTLY INCLUDED IN THE RESTACK, WOULD NORTH DAKOTA  
16 CUSTOMERS BE PAYING FOR ENERGY AND CAPACITY THAT IS NOT NEEDED?

17 A. No. With respect to energy, this resource addition will likely displace the  
18 production of energy from other resources on the system. Because the system  
19 must always balance generation and load, all of our customers use the energy  
20 that is produced by these new resource additions when they are generating.<sup>3</sup>  
21 Therefore, the Restack is merely re-pricing energy that is being consumed by  
22 our North Dakota customers.

23  

---

<sup>3</sup> The Company may also sell energy to third parties. Under the Settlement Agreement in Case No. PU-12-813, we will credit back to customers 100 percent of the earnings on such sales.

1 Q. IF THE RESOURCE ADDITION SIMPLY DISPLACES ENERGY ALREADY ON THE  
2 SYSTEM, WOULDN'T THAT SUGGEST THE APPROPRIATE PROXY IS THE AVERAGE  
3 SYSTEM FUEL COST?

4 A. There is no "correct" answer to this question, only different policy outcomes  
5 that can be achieved through the use of proxy pricing. It is arguable that the  
6 true financial impact to the NSP System of the 187 MW solar portfolio would  
7 be the actual production costs of the NSP generation resources that are  
8 displaced by the 187 MW solar portfolio when the solar portfolio is  
9 generating. However, because MISO and not the Company dispatches all  
10 generation in MISO, the MISO Locational Marginal Pricing for the hours that  
11 the 187 MW solar portfolio is generating represents the cost to the Company  
12 of the energy it would have used to replace the generation of the solar  
13 portfolio.

14  
15 In contrast, utilizing system average as a replacement proxy does not account  
16 for the marginal cost of the energy that the 187 MW solar portfolio displaces.  
17 Rather, a system average cost of fuel without the 187 MW solar portfolio  
18 represents a look at system costs without the 187 MW solar portfolio or some  
19 other resource that would have been generating in its stead.

20  
21 Q. PLEASE ADDRESS WHETHER NORTH DAKOTA CUSTOMERS WOULD BE PAYING  
22 FOR *CAPACITY* THAT THEY DO NOT NEED.

23 A. Unlike energy, capacity is additive to the system and does not displace other  
24 capacity. Our resource planning efforts take into account the lumpy nature of  
25 capacity additions when planning for future additions to the system. By  
26 providing for capacity in the Restack Agreement, the negotiating principles in  
27 our rate case Settlement Agreement recognize the impact that capacity

1 additions have on the need for and timing of the next increment of capacity  
2 for the system. When the Company adds the capacity represented by the 187  
3 MW solar portfolio, the size, type, and timing of any future resource additions  
4 will be affected.

5  
6 Q. WHY MUST CAPACITY BE INCLUDED IN THE RESTACK TO MAINTAIN THE  
7 INTEGRITY OF THE INTEGRATED SYSTEM?

8 A. In short, we plan and operate the NSP System on an integrated basis, and as a  
9 result the addition of new resources impacts our system-wide capacity needs  
10 into the future for all of the states we serve. If our North Dakota customers  
11 do not contribute to the addition of new used and useful capacity, I believe it  
12 would be inappropriate for us to allocate the new capacity to address any  
13 future capacity shortfalls for our North Dakota customers. Rather, the  
14 Company would seek to mitigate its inability to recover the costs of this new  
15 capacity either by reallocating it to other jurisdictions within our integrated  
16 system, or seek to sell the new capacity to a third party. Doing so would be a  
17 departure from the integrated system approach.

18  
19 **C. Implications of Direct Assignment**

20 Q. MR. DILLER RECOMMENDS THAT XCEL ENERGY DIRECT-ASSIGN GENERATION  
21 TO ITS NORTH DAKOTA CUSTOMERS AS A WAY TO ADDRESS DIVERGENT STATE  
22 ENERGY POLICIES. HOW DO YOU RESPOND?

23 A. Mr. Diller states his policy perspective on page 8:21-23 that “basic cost  
24 allocation and rate design principles require that costs be assigned to the cost  
25 causers whether allocating costs between states or to various customer  
26 classes.” I agree with Mr. Diller’s perspective and that cost causation is an

1 important consideration. But cost causation isn't the only relevant criteria to  
2 inform the Commission's consideration.

3  
4 I think it is important that the Commission also recognize that our integrated  
5 five-state system allows us to plan and implement it on a consolidated basis in  
6 order to meet all of our customers' needs as well as complying with all of the  
7 policies in all of our states. Overall this has proved to be a cost-effective way  
8 for us to serve our North Dakota customers as well as the customers in the  
9 other four states. While it may be true that some of the costs we incur are  
10 designed to address specific policies in Minnesota, we do not believe this  
11 nullifies the overall value of the integrated system to our customers in North  
12 Dakota.

13  
14 Q. WHAT ARE SOME OF THE IMPLICATIONS IF THE COMMISSION DECIDES TO  
15 ADOPT A POLICY OF DIRECT-ASSIGNING GENERATION CONSISTENT WITH  
16 NORTH DAKOTA'S ENERGY POLICY?

17 A. If one state requires that we direct-assign generation to avoid the impact of  
18 another state's energy policy, we will no longer be able to manage the NSP  
19 System as an integrated whole since some capacity component of our resource  
20 additions will not be available to the system. This will require us to plan for  
21 and manage our North Dakota customers on a separate basis than the  
22 remainder of the NSP System.

23  
24 Q. WOULD THE OUTCOME BE THE SAME IF THE COMMISSION DENIED AN ADP  
25 FOR THE COMPANY'S REQUESTED RESOURCE ADDITION AND DID NOT ALLOW  
26 THE ENERGY OR CAPACITY COSTS TO BE RE-PRICED THROUGH THE RESTACK  
27 PROCESS?

1 A. Yes. Rejecting the capacity from the Restack, as Mr. Diller recommends,  
2 would eliminate this capacity from consideration for serving our North  
3 Dakota customers. This will make it impossible to continue to fully integrate  
4 our North Dakota customers into the NSP System on a going-forward basis.

5

6 Q. PLEASE EXPLAIN.

7 A. Eliminating the capacity component from recovery in the Restack would  
8 mean that North Dakota could not take advantage of that capacity since it  
9 would be making no contribution to the cost of that generation. This would  
10 require the Company to plan separately for how to meet North Dakota's  
11 capacity needs. Ultimately, this would result in a separate analysis of when  
12 new generation is needed to serve our North Dakota customers and would  
13 require that we deploy generation specifically dedicated to North Dakota.

14

15 Q. DO YOU HAVE GENERAL CONCERNS OVER DIRECT-ASSIGNING CAPACITY AWAY  
16 FROM NORTH DAKOTA?

17 A. Yes. In order to maintain the integrated system, we must be able to allocate  
18 all of our generation across all of our states. If a state chooses to reject a  
19 particular resource, then that generation must be allocated away from that  
20 state to avoid the state using capacity it is not paying for. Ultimately, direct-  
21 assignment would require the Company to separate its utility operations by  
22 jurisdiction to ensure that all capacity being dedicated to each jurisdiction is  
23 properly accounted for.

24

25 Q. ARE THERE OTHER PROBLEMS WITH THE CONCEPT OF DIRECT-ASSIGNMENT?

26 A. Yes. Direct-assigning generation away from North Dakota raises the risk that  
27 North Dakota could find itself in a capacity deficit position (on an individual

1 basis) even if NSP's overall portfolio would have enough generation to serve  
2 North Dakota but for the fact that some of that generation was direct-  
3 assigned away.

4  
5 Q. WHAT WOULD THE COMPANY HAVE TO DO IF IT FORECASTED A CAPACITY  
6 DEFICIENCY FOR ITS NORTH DAKOTA OPERATION AND WAS UNABLE TO PLAN  
7 FOR THE NSP SYSTEM ON AN INTEGRATED BASIS?

8 A. We would have to procure additional resources specifically dedicated to North  
9 Dakota to make up for the deficit created by direct-assigning existing capacity.  
10 We could do this by purchasing capacity from another utility (if it was  
11 available) or we could try to obtain that capacity using the MISO voluntary  
12 capacity auction. However, as described above, procuring capacity through  
13 those market mechanisms is risky and not assured. We could also seek to  
14 obtain capacity through either short-term or long-term bilateral transactions.

15  
16 Another alternative is that the Company would need to build additional  
17 capacity for our North Dakota customers to meet that deficit. In this  
18 scenario, we would consider the size, type and timing of construction to  
19 address this deficit and would expect that it would be a smaller unit than  
20 would be possible if we were planning for the NSP System on an integrated  
21 basis.

22  
23 I note that because this would be a resource dedicated to meeting only our  
24 North Dakota customers' capacity needs, we would anticipate direct-assigning  
25 these costs to our North Dakota jurisdiction.

26  
27 Q. WHAT DO YOU RECOMMEND?

1 A. I recommend that the Commission decline to direct-assign generation on the  
2 Company's system and that the Commission allow us to reflect the used and  
3 useful portion of the capacity we propose to add to our system. In this  
4 instance, we recommend that the Commission grant the requested ADP for  
5 the 187 MW solar portfolio or, in the alternative, allow both the energy and  
6 capacity from this purchase to be re-priced through the North Dakota Restack  
7 process.

8  
9 **VI. CHANGES TO PPAS**

10  
11 Q. HAVE THE PPAS CHANGED SINCE THE TIME THEY WERE FILED WITH THE  
12 COMMISSION WITH THE COMPANY'S APPLICATION?

13 A. Yes, minor edits were made to the PPAs. The only substantive edit was to  
14 conform the regulatory approval language with the PPA we entered into for  
15 the Geronimo Solar Project that is the subject of Case No. PU-15-095. These  
16 conforming changes were made by letter agreement between the Company  
17 and PPA developers and are attached as Schedule 2<sup>4</sup>.

18  
19 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

20 A. Yes, it does.

---

<sup>4</sup> See also March 24, 2015 ORDER APPROVING SOLAR PORTFOLIO in MPUC Docket No. E002/M-14-162.



**PUBLIC DOCUMENT –  
TRADE SECRET DATA EXCISED**

Case No. PU-14-810  
Exhibit \_\_\_(KJH-2), Schedule 1  
Page 1 of 21

Direct Testimony and Schedules  
Kurtis J. Haeger

Before the North Dakota Public Service Commission  
State of North Dakota

In the Matter of the Application of Northern States Power Company for an  
Advance Determination of Prudence for a Power Purchase Agreement with Aurora  
Distributed Solar, LLC for up to 100 MW of Solar Generation

Case No. PU-15-\_\_\_\_\_  
Exhibit \_\_\_(KJH-1)

**Resource Planning Policy Testimony**

February 13, 2015

**PUBLIC DOCUMENT –  
TRADE SECRET DATA EXCISED**

**TABLE OF CONTENTS**

I.	Introduction and Qualifications	1
II.	Resource Need	2
III.	Implications of Need Assessment	6
IV.	MPUC Assessment of Need	10
V.	Company ADP Request	13

**Schedules**

Resume  
Geronimo Solar PPA

Schedule 1  
Trade Secret Schedule 2

**PUBLIC DOCUMENT –  
TRADE SECRET DATA EXCISED**

**I. INTRODUCTION AND QUALIFICATIONS**

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Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Kurtis J. Haeger. I am the Managing Director of Resource Planning for Xcel Energy Services Inc. (XES), the service company subsidiary of Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been employed by Xcel Energy or one of its predecessors for over 30 years and assumed my current position as Managing Director of Resource Planning in 2004.

I am responsible for managing the development and implementation of the electric resource plans for all the Operating Companies of Xcel Energy. I also have responsibility for managing the bidding and evaluation processes for acquiring new electric generation resources and for managing the technical analysis for supporting Xcel Energy’s regulatory filings associated with its requests to construct and own new generation facilities. Additionally, I am responsible for directing the analytical support for Xcel Energy’s renewable energy plan filings.

My resume is provided as Exhibit\_\_\_\_(KJH), Schedule 1

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present the resource planning policy issues related to the Company’s requested Advanced Determination of Prudence (ADP) for the Geronimo Solar power purchase agreement (PPA), which is included as Trade Secret

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1 Exhibit\_\_\_(KJH-1), Schedule 2 to my testimony. More specifically, I address  
2 the following:

- 3 • The Company’s utilization of its Fall 2011 Forecast to establish this  
4 need that is being met by the Geronimo Solar PPA;
- 5 • The impacts that demand forecast variability have on the nature and  
6 timing of our resource acquisition decisions; and
- 7 • The impacts o four proposed resource acquisitions on the “Restack”  
8 concept established in the Settlement Agreement in Case No. PU-12-  
9 813.

10  
11 **II. RESOURCE NEED**

12  
13 Q. IS THE COMPANY PROPOSING ITS RESOURCE ADDITION TO MEET AN  
14 IDENTIFIED NEED?

15 A. Yes. The Company has identified a need of between 150-500 MW of  
16 additional capacity in the 2017-2019 time frame. Company Witness Mr. Paul  
17 B. Johnson discusses this need further in his Direct Testimony.

18  
19 Q. HOW DID THE COMPANY IDENTIFY THIS NEED?

20 A. Our capacity need is based on our updated Fall 2011 forecast (Fall 2011  
21 Forecast). This forecast updated the initial demand and energy forecast  
22 included in our 2010 Resource Plan.

23  
24 Q. DID THIS INFORMATION ALSO FORM THE BASIS UNDERLYING THE COMPANY’S  
25 FILINGS IN CASE NO. PU-13-194?

26 A. Yes, augmented with information from the Company’s Spring 2013 forecast,  
27 the Fall 2011 Forecast is the forecast used in our advance determination of

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1 prudence application for Black Dog Unit 6 and Red River Valley Units 1 and 2  
2 (Case No. PU-13-194 (Gas CTs Case)). Mr. Johnson discusses in his Direct  
3 Testimony our resource planning efforts that led to our proposal in the Gas  
4 CTs Case.

5  
6 Q. WHAT NEED DID THE 2010 RESOURCE PLAN FORECAST IDENTIFY?

7 A. The initial forecast presented in our 2010 Resource Plan (Case No. PU-10-  
8 580) identified a resource need of 963 MW BY 2020 AND 2,003 MW BY 2025.  
9 To meet that need, the 2010 Resource Plan proposed a 680 MW combined  
10 cycle gas plant to be built at the Company's existing Black Dog site along with  
11 780 MW of combustion turbines (CT) by 2024.

12  
13 Q. WHAT NEED DID THE FALL 2011 FORECAST IDENTIFY?

14 A. The Fall 2011 Forecast identified a capacity need of approximately 150 MW  
15 beginning in 2017 that grows up to approximately 500 MW in 2019/2020, and  
16 suggested a capacity need growing to 920 MW by 2024.

17  
18 Q. WHAT ACCOUNTS FOR THE DIFFERENCE BETWEEN THE 2010 RESOURCE PLAN  
19 FORECAST AND THE FALL 2011 FORECAST?

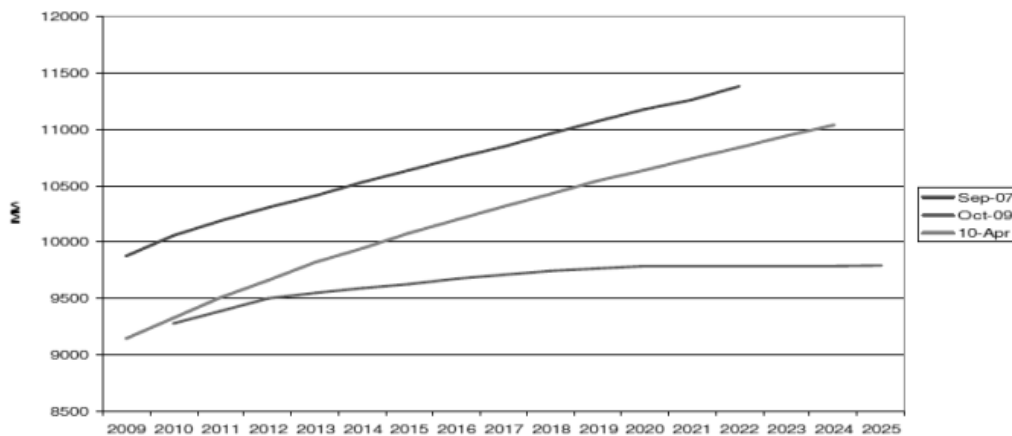
20 A. Peak demand forecasts vary as economic conditions change over time. The  
21 forecast of future economic growth is one of the key measures that drives  
22 growth in demand and energy. Due to the significant downturn of the  
23 economy during the 2008 recession and the uncertainty in the recovery for the  
24 five to six years that followed, accurately predicting economic factors along  
25 with demand and energy usage has been a challenge. Attempting to predict  
26 the magnitude and timing of an economic recovery has puzzled many, and has  
27 also resulted in the Company having wide fluctuations in demand and energy

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1 forecasts during this time period. As a result, if actual circumstances do not  
2 match the assumptions used to develop the forecast, then actual results will be  
3 different than the forecasted results.

4  
5 Our 2010 Resource Plan was the Company’s first Resource Plan that sought to  
6 incorporate our estimates of the effect of the economic recovery from the  
7 2008 recession. Figure 1.3 from our 2010 Resource Plan, below, demonstrates  
8 the variability of our forecasts due to the 2008 recession and the expected  
9 recovery that followed.

**Figure 1.3  
Demand Forecast Over Time**



10  
11 Our Spring 2010 forecast expected a stronger economic recovery than what  
12 occurred. As a result, the 2010 forecast showed a rebound in need compared  
13 to the 2009 forecast. By the fall of 2011, however, a more robust recovery  
14 was not occurring and therefore the demand and energy need in the 2011 Fall  
15 Forecast was less strong than we anticipated the previous year. While we  
16 recognize that North Dakota has been experiencing growth at a faster pace  
17 than the rest of the region, it has not been sufficient to offset the more

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1 sluggish recovery in the other jurisdictions served by the NSP System.

2

3 Q. HAS THE COMPANY UPDATED ITS FORECASTS SINCE THE FALL 2011  
4 FORECAST?

5 A. Yes. Regularly updating our load forecasts is a normal part of our resource  
6 planning efforts. Since developing our Fall 2011 Forecast, we have updated  
7 our load forecast five times: in the spring of 2012, in the fall of 2012, in the  
8 spring of 2013, in the fall of 2014, and in 2015.

9

10 Q. WHAT DID THESE FORECASTS UPDATES INDICATE?

11 A. In general our forecast updates since 2011 have continued to show a sluggish  
12 recovery and a delay in the expected growth that we had forecast earlier. As a  
13 result, the more recent updates have continued to show a slower rebound in  
14 growth and a lower overall capacity need. Our 2015 Resource Plan forecast  
15 indicated a capacity surplus of 313 MW in 2017 decreasing to 151 MW in  
16 2019, and suggested a need of 165 MW in 2024.

17

18 Q. IS THE VARIABILITY IN THESE MORE RECENT FORECASTS UPDATES SIMILAR TO  
19 THE VARIABILITY EXPERIENCED FROM 2008 TO 2011?

20 A. Yes, the variability in these subsequent updates is heavily influenced by the  
21 same factors that accounted for the variability between our 2010 Resource  
22 Plan forecast and our Fall 2011 Forecast. Since the recession of 2008, it has  
23 been difficult to predict what kind of economic conditions will result due to  
24 the uncertainty of the strength and timing of the economic recovery across the  
25 region.

26

27 While the range of these more recent forecasts falls within an error band, or

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1 probability range, of only two to three percent, these changes result in varying  
2 estimates of peak demand by approximately 250 MW within the 2016-2020  
3 timeframe.

4  
5 **III. IMPLICATIONS OF NEED ASSESSMENT**

6  
7 Q. WHAT ARE THE IMPLICATIONS OF THE VARIABILITY OF DEMAND FORECASTS  
8 OVER TIME?

9 A. The variability in our forecasts since the Fall 2011 Forecast, which established  
10 our baseline resource need, indicates that the NSP System could be in deficit  
11 between 2017 and 2024. And, while our most recent 2105 Resource Plan  
12 forecast suggests weakening demand, this forecast also demonstrates that our  
13 capacity position in 2019 and 2020 is very near a deficit. In other words, our  
14 forecast updates have demonstrated a slackening of demand that could argue  
15 to postpone making capacity additions. However, we believe that a  
16 conservative approach to meeting our needs is appropriate at this time.

17  
18 Q. PLEASE ELABORATE.

19 A. Fundamentally, this issue is related to the appropriate way to determine and  
20 then meet resource needs. We could continually update our forecasts and  
21 then only act when the size and timing of a need is absolutely certain. This  
22 would require us to wait until very close in time for our need to develop to  
23 ensure we have the certainty that there is a need to be filled. While this course  
24 of action would postpone any investment until need is certain, it could  
25 potentially significantly limit our options as to how to meet that need given  
26 the lack of time to develop proposals and probe the market for cost effective  
27 resources. Further, short term solutions such as capacity market purchases

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1 would leave us vulnerable to potentially increasing spot market pricing at the  
2 exact time we would need to contract for capacity. In other words, meeting  
3 the need and maintaining reliability would take precedence over cost  
4 effectiveness.

5  
6 On the other end of the spectrum, we could identify our needs many years out  
7 and then work to meet that more uncertain need. This would give us plenty  
8 of time to develop cost effective proposals and undergo all necessary  
9 regulatory approvals, which can add years to the development cycle. The  
10 advantages of such an approach is that the Company is in a position to be  
11 flexible as to the timing of resource selection/construction, taking advantage  
12 of periods when costs are lower, the market is not constrained, and financing  
13 costs are possibly lower.

14  
15 Ultimately, the most prudent course of action is somewhere between these  
16 two extremes. It makes the most sense to move forward when a need is  
17 sufficiently certain that it would make sense to add capacity to the system but  
18 far enough into the future to allow the time necessary for the lengthy project  
19 analysis, regulatory approval, and resource development processes.

20  
21 Q. WHAT IS THE COMPANY'S RECOMMENDATION BASED ON THE VARIABILITY IN  
22 THE FORECASTS OF THE COMPANY'S NEED?

23 A. Our recommended course of action is to act conservatively in the face of  
24 uncertainty and make resource additions as a need is forecasted and have  
25 those additions be of a size and type to address the need in a way that also  
26 positions us well for the future. This approach is premised on the assumption  
27 that it is better for a utility to be long than short on capacity, since the utility

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1 has the obligation to serve all of its customers’ needs under all reasonable  
2 circumstances and must have resources available to meet those needs. The  
3 benefits to this approach are that it provides the time needed to make resource  
4 decisions through the use of competitive processes to help bring down the  
5 cost of these resources. Additionally, it avoids exposing the Company - and  
6 ultimately customers - to the short-term capacity markets and the price  
7 uncertainty inherent with such markets. Company Witness Johnson discusses  
8 further in his Direct Testimony how the Geronimo Solar PPA in combination  
9 with the Calpine Project PPA and Black Dog Unit 6 appropriately address our  
10 customer’s need under all reasonable circumstances, specifically including the  
11 softer need forecast in our 2015 Resource Plan.  
12

13 Q. ARE THERE OTHER CIRCUMSTANCES THAT WOULD ALSO SUPPORT THE  
14 PRUDENCE OF MAKING RESOURCE ADDITIONS TO THE SYSTEM NOW?

15 A. Yes. Determining whether to add resources to the NSP System is a fact  
16 specific determination. In this instance, we identified our need almost five  
17 years ago and have moved forward in the project selection and regulatory  
18 approval process consistent with that identified need. While we have been  
19 doing this, our updated forecasts indicate a slackening of demand which could  
20 argue against making a capacity addition at this time. However, this should be  
21 weighed against several other factors including: (1) anticipated MISO-wide  
22 capacity retirement; (2) the currently favorable interest rate and cost  
23 environment; (3) an uncertain environmental regulatory environment; and (4)  
24 low capacity surplus margins.  
25

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1 Q. PLEASE DESCRIBE THE IMPACT THAT Midcontinent Independent System  
2 Operator, Inc., (MISO)-WIDE CAPACITY RETIREMENTS WILL LIKELY HAVE ON  
3 THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

4 A. Our analyses indicate that the cost of generation development, especially gas  
5 fired generation, may become more expensive as demand for new gas-fired  
6 generation increases due to the decommissioning of several coal plants in the  
7 MISO footprint. The plant retirements are also expected to increase the costs  
8 of short-term capacity in MISO's voluntary short-term capacity markets as  
9 such capacity becomes more valuable as resources are constrained. This  
10 argues for making resource additions now, rather than waiting.

11  
12 Q. PLEASE DESCRIBE HOW THE INTEREST RATE AND COST ENVIRONMENT IMPACT  
13 THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

14 A. As relates to cost, the Calpine Project PPA represents some of the lowest cost  
15 combined cycle capacity and energy we have seen. Locking in this low cost  
16 resource will help to mitigate any tightening of capacity that may occur in the  
17 MISO markets.

18  
19 With respect to interest rates, low rates provide less expensive financing for  
20 the Company's project. Moving forward with the Black Dog 6 Project in this  
21 low-interest rate environment can lock in cheaper financing now than risk  
22 more expensive financing in the future.

23  
24 Q. PLEASE DESCRIBE HOW AN UNCERTAIN ENVIRONMENTAL REGULATORY  
25 ENVIRONMENT SUPPORTS ADDING RESOURCE ADDITIONS AT THIS TIME.

26 A. Positioning the NSP System for an uncertain regulatory future with respect to  
27 greenhouse gas and other environmental requirements through the addition of

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1 new solar and gas-fired generation makes sense given that we would secure the  
2 innovative use of solar as a capacity resource through the Geronimo Solar  
3 PPA, and very attractive pricing for the Calpine Project PPA. Additionally,  
4 gaining experience with managing solar capacity interconnected to our  
5 distribution system also provides benefits now while positioning us for the  
6 increase in the use of this generation type into the future.

7  
8 Q. PLEASE DESCRIBE HOW THE ANTICIPATED MARGIN OF SURPLUS CAPACITY  
9 AFFECTS THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

10 A. Our demand forecast variability, and the small margin that we have on our  
11 current system, argue to move forward with capacity additions now in case our  
12 forecasts turn out to be inaccurate and the NSP System could become short.

13  
14 **IV. MPUC ASSESSMENT OF NEED**

15  
16 Q. DID THE FALL 2011 FORECAST UPDATE FORM THE BASIS OF REGULATORY  
17 REVIEW OF THE COMPANY'S PROPOSAL IN NORTH DAKOTA AND MINNESOTA?

18 A. Yes. At the time we made our initial filing in the Minnesota Competitive  
19 Acquisition Process (CAP) proceeding (Docket No. E002/CN-12-1240), the  
20 Fall 2011 Forecast was the most up-to-date information available. The Fall  
21 2011 Forecast formed the underlying basis for establishing need in that  
22 proceeding, but as I previously noted was updated several times.

23  
24 Q. DID THE COMPANY ONLY RELY UPON THE UPDATED 2011 FORECAST IN  
25 PRESENTING RESOURCE OPTIONS TO THE MINNESOTA PUBLIC UTILITIES  
26 COMMISSION (MPUC)?

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1 A. No. Prior to the MPUC’s May 23, 2014 Order directing the Company to  
2 negotiate PPAs with Geronimo, Calpine, and Invenergy so that the MPUC  
3 could determine which of these resources to approve for acquisition to meet  
4 our need, we updated our forecast through September 2013. This updated  
5 forecast identified a slackening of need of 117 MW in 2017, 118 MW in 2018  
6 and 123 MW in 2019.

7

8 Q. DID THE MPUC AGREE WITH THIS FORECAST UPDATE?

9 A. The MPUC considered the September 2013 update as a valid data point  
10 from which to consider its decision. However, the MPUC did not conclude  
11 that the September 2013 update justified changing their 2010 Resource Plan  
12 conclusion that the NSP System requires between 150 and 500 MW of new  
13 capacity in the 2017-2019 timeframe. To the contrary, the MPUC concluded  
14 that the update, when coupled with all of the other data points in the record,  
15 supported taking a conservative approach to plan for up to 500 MW of new  
16 capacity.

17

18 Q. DID THE COMPANY PROVIDE ANY ADDITIONAL UPDATES?

19 A. Yes. On September 23, 2014 we made a compliance filing with the  
20 MPUC, presenting draft PPAs the Company negotiated with Geronimo,  
21 Calpine, and Invenergy. In that filing we updated our customer demand  
22 forecast, and provided information about the then-current resource  
23 assessment. We believed this information suggested that our capacity need  
24 had changed from an *increasing need* to a *flat capacity surplus* through as late as  
25 2023. This conclusion was supported by two factors: (1) continuing flat  
26 demand growth, and (2) continuing evolution of the MISO reserve margin  
27 requirements which suggested we required lower reserves than we had



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1 Finally, the [Minnesota] Commission’s goal is  
2 not to forecast the precise level of need – a  
3 task rife with the potential for error – but to  
4 identify the resource mix that will best  
5 manage forecasting error . . . . Based on the  
6 state of the record regarding Xcel’s latest need  
7 assessment, the Commission will decline to  
8 alter its finding of need on this basis.  
9

10 Q. DOES XCEL ENERGY AGREE WITH THE MPUC’S DECISION TO CHOOSE NEW  
11 CAPACITY DESPITE THE MOST RECENT FORECASTS SHOWING A REDUCED  
12 NEED?

13 A. The Company accepts that there are a number of ways to review capacity  
14 needs and that any single forecast is not determinative. While we provided  
15 information that suggests deferring the acquisition of additional capacity  
16 could be appropriate, we are comfortable that acquiring capacity at this time  
17 is consistent with the long-term needs of our customers.  
18

19 **V. COMPANY ADP REQUEST**  
20

21 Q. WHAT IS THE COMPANY’S REQUEST IN THIS PROCEEDING?

22 A. The Company is requesting that the Commission grant an ADP for the  
23 Geronimo Solar PPA. As described in our application and supporting  
24 testimony, this PPA, as well as the Calpine Project PPA, are prudent resources  
25 to meet our capacity needs in the 2017-2020 time frame.  
26

27 Q. COULD THE COMMISSION DENY THE COMPANY’S REQUEST?

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1 A. While our decision to add 500 MW of capacity to the system at this time is  
2 prudent, we recognize that this is based on a conservative assessment of need  
3 and that the Commission could make a different policy judgment. Further, we  
4 recognize that the Commission could disagree with our choice of resources to  
5 meet this need. If this were to occur, we respectfully request that any resource  
6 for which the Commission does not grant an ADP be included in the  
7 “Restack Agreement” that the Company is currently negotiating with  
8 Commission Staff.

9

10 Q. WHY WOULD IT BE APPROPRIATE TO INCLUDE A RESOURCE FOR WHICH THE  
11 COMMISSION DOES NOT GRANT AN ADP IN THE RESTACK?

12 A. The Company views the Restack as a reasonable short- to mid-term tool to  
13 address the continuing divergence of state energy policies and their impact on  
14 the integrated NSP System, which allows us the time to find a long-term  
15 mechanism to address this continuing issue. Should the Commission not  
16 deem our proposal – which implements the MPUC’s recommendation in the  
17 CAP Docket both as to need and the resources to meet that need – prudent,  
18 we believe that utilizing the Restack methodology for these resources will  
19 provide an avenue that will allow us to continue to plan and operate the NSP  
20 System on an integrated basis while long-term solutions to divergent energy  
21 policies are developed.

22

23 Q. HOW WILL THE RESTACK ALLOW THE COMPANY TO CONTINUE TO PLAN AND  
24 OPERATE THE NSP SYSTEM ON AN INTEGRATED BASIS?

25 A. As the Commission is aware, development of the Restack Agreement is  
26 guided by ten negotiating principles adopted by the Commission in the  
27 Settlement Agreement of our last rate case. Key among these principles is that

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1 any proxy pricing for restacked resources reflects both the energy and capacity  
2 impacts of any new resource addition (such as those proposed by the  
3 Company here) that have been rejected by the Commission. By addressing  
4 both the capacity and energy impacts of new resource additions, the Restack  
5 will recognize the used and useful nature of these resource additions to the  
6 NSP System while mitigating the cost impact on our North Dakota customers  
7 of energy policy decisions made in other states with which the Commission  
8 does not concur.

9  
10 The Settlement Agreement’s negotiating principles outlined that the  
11 appropriate proxy pricing would reflect the marginal cost of the next unit of  
12 capacity or energy available to be added to the system. We are continuing to  
13 negotiate the appropriate proxy pricing for this “marginal” cost for both  
14 capacity and energy with Commission Staff, which will establish the “used and  
15 useful” pricing for any new resource additions subject to the Restack.

16  
17 Q. WHY IS IT IMPORTANT THAT BOTH ENERGY AND CAPACITY IMPACTS BE  
18 ACCOUNTED FOR IN THE RESTACK METHODOLOGY?

19 A. The Restack concept is premised on the ability to continue to plan and  
20 operate the NSP System as an integrated whole while addressing the impact of  
21 different state energy policies on our North Dakota customers. To meet these  
22 objectives, we have proposed a methodology where a proxy price for energy  
23 and capacity would replace the actual cost of the new resource addition in  
24 rates. By utilizing a proxy price, the costs of the proposed new resource  
25 addition can be measured against an objective standard (*i.e.* the cost of the  
26 next increment of energy or capacity to the system) to determine what type of  
27 “policy premium” exists for the resource addition. By accounting for capacity

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1 and energy, our North Dakota customers are still contributing to used and  
2 useful resource on the integrated system and for the energy they use and the  
3 capacity that is serving them.

4  
5 Q. IF THE COMMISSION WERE TO DENY AN ADP FOR THE COMPANY’S PROPOSED  
6 RESOURCE ADDITIONS BECAUSE IT DETERMINES THAT THERE IS NO NEED TO  
7 ADD CAPACITY AT THIS TIME, BUT ALLOWS THESE RESOURCE ADDITIONS TO BE  
8 INCLUDED IN THE RESTACK, WOULD NORTH DAKOTA CUSTOMERS BE PAYING  
9 FOR ENERGY AND CAPACITY THAT THE COMMISSION DETERMINES IS NOT  
10 NEEDED?

11 A. No. With respect to energy, as discussed in the Direct Testimony of Mr.  
12 Johnson, our resource additions will likely displace the production of energy  
13 from other resources on the system. Because the system must always balance  
14 generation and load, all of our customers use the energy that is produced by  
15 these new resource additions when they are generating.<sup>1</sup> Therefore, the  
16 Restack is merely repricing energy that is being consumed by our North  
17 Dakota customers.

18  
19 Capacity, on the other hand, is additive to the system and does not displace  
20 other capacity. Our resource planning efforts take into account the lumpy  
21 nature of capacity additions when planning for the next capacity additions to  
22 the system. By providing for capacity in the Restack Agreement, the  
23 negotiating principles in our rate case Settlement Agreement recognize the  
24 impact that capacity additions have on the need for and timing of the next  
25 increment of capacity for the system.

---

<sup>1</sup> The Company may also sell energy to third parties. Under the Settlement Agreement in Case No. PU-12-813, we will credit back to customers 100% of the earnings on such sales.

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26

Q. WHY DOES CAPACITY HAVE TO BE ACCOUNTED FOR IN THE RESTACK TO MAINTAIN THE INTEGRITY OF THE INTEGRATED SYSTEM?

A. Our resource planning takes into account all accredited capacity on our system to determine the size and timing of our future capacity needs. By doing so, we account for all resources, including those added to meet other states’ energy policy goals such as solar resources, as well as traditional thermal resources. When the Company adds the capacity represented by the Geronimo Solar PPA and Calpine Project PPA, as well as Black Dog Unit 6, to the system, the size, type, and timing of any future resource additions will be affected.

In short, we plan and operate the NSP System on an integrated basis, and as a result the addition of new resources impacts our system-wide capacity needs into the future for all of the states we serve. If our North Dakota customers do not contribute to the addition of new used and useful capacity, I believe it would be inappropriate for us to allocate the new capacity to address any capacity shortfalls for our North Dakota load. Rather, the Company would seek to mitigate its inability to recover the costs of this new capacity either by reallocating it to other jurisdictions within our integrated system, or seek to sell the new capacity to a third party.

If this were to occur, we will no longer be able to manage the NSP System as an integrated whole since some capacity component of our resource additions – in this instance roughly 18 to 20 MW representing North Dakota’s allocation of the approximately 350 MW of capacity provided by the Geronimo Solar PPA and Calpine Project PPA – will not be available to the

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1 system. This will require us to plan for and manage our North Dakota load  
2 on a separate basis than the remainder of the NSP System.

3  
4 Q. WOULD THE OUTCOME BE THE SAME IF THE COMMISSION DENIED AN ADP  
5 FOR THE COMPANY'S REQUESTED RESOURCE ADDITION AND DID NOT ALLOW  
6 IT TO BE INCLUDED IN THE RESTACK.

7 A. Yes. As I mentioned, the Restack mechanism, with proxy pricing for capacity,  
8 will provide short- to mid-term mitigation of the impact that different states'  
9 determinations with respect to adding new capacity to our system may have  
10 on our North Dakota customers while ensuring they contribute something  
11 towards the used and useful capacity. We believe the Restack will provide us  
12 with time to more completely address divergent energy policies. However, if  
13 the Commission rejects our ADP, or if the Restack is rejected by the  
14 Commission or does not account for capacity added to the system, we believe  
15 that it will be challenging to continue to integrate our North Dakota  
16 customers into the NSP System on a going forward basis.

17  
18 Q. WILL THE COMPANY PROPOSE ANY ALTERNATIVES SHOULD THE COMMISSION  
19 CHOOSE NOT TO ALLOW FOR CAPACITY PROXY PRICING FOR THOSE RESOURCES  
20 FOR WHICH THERE IS NO DEMONSTRATED NEED?

21 A. We have demonstrated that our proposed resource additions are prudent and  
22 respectfully request that the Commission grant our requested ADP. In the  
23 alternative, we respectfully request that the Commission allow us to include  
24 our resource additions in the Restack Agreement and address appropriate  
25 implementation of capacity proxies as part of those negotiations. Should the  
26 Commission reject our ADP and the Restack Agreement, it is incumbent

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1       upon the Company to propose solutions to the impact that divergent state  
2       energy policies have on us and all of our customers.

3

4    Q.   DOES THIS CONCLUDE YOUR TESTIMONY?

5    A.   Yes, it does.



1800 Larimer Street, Suite 1000  
Denver, CO 80202

April 2, 2015

Mr. Tim Oliver  
Executive Director  
NextEra Energy Resources, LLC  
700 University Boulevard  
Juno Beach, Florida 33408

Mr. Mitch Ross  
Vice President and General Counsel  
NextEra Energy Resources, LLC  
700 University Boulevard  
Juno Beach, Florida 33408

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Oliver,

Northern States Power Company ("Company") and Marshall Solar, LLC, ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the 'PPA') dated as of March 3, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change Exhibit A, Definitions, "State Regulatory Approval" so that the definition now reads: "State Regulatory Approval" occurs after a final written order is received from one State Regulatory Agency, or if needed, both State Regulatory Agencies, and means final written orders that (i) are not subject to application for rehearing, reargument or reconsideration and (ii) singly or in the aggregate make affirmative determination that Company's execution of this PPA is prudent and/or in the public interest, and that all costs incurred under this PPA as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA.

Seller and Company acknowledge and agree that this letter does not constitute an amendment to the PPA, which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

**NORTHERN STATES POWER COMPANY**

By: 

Name: Thomas A. Imbler

Title: Vice President, Commercial Operations

Xcel Energy Services Inc. as agent for

Northern States Power Company

Acknowledged and agreed to this 14 day of April, 2015.

**Marshall Solar, LLC**



Michael O'Sullivan

Vice President



1800 Larimer Street, Suite 1000  
Denver, CO 80202

April 6, 2015

Jay T. Sonnenberg  
General Counsel  
MN Solar I LLC  
c/o juwi solar Inc.  
1710 29<sup>th</sup> Street, Suite 1068  
Boulder, CO 80301

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Sonnenberg,

Northern States Power Company ("Company") and MN Solar I LLC ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the 'PPA') dated as of February 19, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change Exhibit A, Definitions, "State Regulatory Approval" so that the definition now reads: "State Regulatory Approval" means final written orders from one State Regulatory Agency, or if needed, both State Regulatory Agencies that (i) are not subject to application for rehearing, reargument or reconsideration, and (ii) singly or in the aggregate make an affirmative determination that Company's execution of this PPA is prudent and/or in the public interest, and that all costs incurred under this PPA as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA.

Seller and Company acknowledge and agree that this letter does not constitute an amendment to the PPA, which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

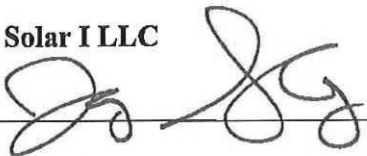
**NORTHERN STATES POWER COMPANY**

By: 

Name: Thomas A. Imbler  
Title: Vice President, Commercial Operations  
Xcel Energy Services Inc. as agent for  
Northern States Power Company

Acknowledged and agreed to this 6th day of April, 2015.

**MN Solar I LLC**



Jay Sonnenberg  
Secretary



1800 Larimer Street, Suite 1000  
Denver, CO 80202

April 13, 2015

Mr. Eric Blank  
Manager  
North Star Solar PV LLC  
3 Radnor Corporate Center, Suite 300  
100 Matsonford Road  
Radnor, PA 19087

Ms. Molly Arbes  
Treasurer  
Community Energy, Inc.  
3 Radnor Corporate Center, Suite 300  
100 Matsonford Road  
Radnor, PA 19087

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Blank:

Northern States Power Company ("Company") and North Star Solar PV LLC ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the "PPA") dated as of March 6, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change Exhibit A, Definitions, "State Regulatory Approval" so that definition now reads "State Regulatory Approval occurs after a final written order is received from one State Regulatory Agency, or if needed, both State Regulatory Agencies, and means final written orders that: (i) are not subject to application for rehearing, reargument or reconsideration, (ii) singly or in the aggregate make an affirmative determination that Company's execution of this PPA is prudent and/or in the public interest and (iii) that all costs incurred under this PPA, as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions, are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA."

Seller and Company acknowledge and agree that except as expressly set forth in this letter, nothing herein shall (i) affect the rights or obligations of the Parties as contained in the PPA or (ii) amend the terms of the PPA which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

**NORTHERN STATES POWER COMPANY**

By:     T. A. Imbler    

Name: Thomas A. Imbler  
Title: Vice President, Commercial Operations  
Xcel Energy Services Inc., as agent for  
Northern States Power Company

Acknowledged and agreed to this 14 day of April, 2015.

**North Star Solar PV LLC**

    Eric Blank    

Name: Eric Blank  
Title: Executive Vice President