Xcel Energy®

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September 23, 2014

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: COMPLIANCE
COMPETITIVE RESOURCE ACQUISITION
DOCKET NOS. E002/CN-12-1240 & E002/CN-13-606

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission a Compliance filing including its updated resource need assessment, and negotiated draft Purchased Power Agreements between the Company and Calpine Energy, Invenergy, and Geronimo – as well as the Company's Black Dog Unit 6 pricing.

We have prepared Public, Non-Public Trade Secret, and Non-Public Highly Sensitive Trade Secret Information versions of this Compliance filing. The most restricted version is that which contains Highly Sensitive Trade Secret Information – Third Party Confidential Information in the body of the Comments and in Attachment D to the Comments. Per the terms of the October 1, 2013 Fifth Prehearing Order, and consistent with the practice in this matter, we are submitting the Highly Sensitive Trade Secret version only in Docket No. E002/CN-13-606. Since this version contains Third Party Confidential Information, consistent with the terms of paragraph 2(c) of the Fifth Prehearing Order, this version is only being served on the governmental agencies who are parties in this docket.

We are also filing a Non-Public Trade Secret version of our filing in E002/CN-12-1240. In this version, we have redacted the Third Party Confidential Information. It, however, contains Trade Secret information applicable to the Power Purchase Agreements and the pricing proposal for Black Dog 6. The Trade Secret information is contained in the body of the Comments and in Attachments A, B, and C. We are also submitting a Public version of our Comments in Docket No. E002/CN-12-1240, which does not contain the restricted material contained in the other versions of this filing.

We have electronically filed the Public and Non-Public versions with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. The Highly Sensitive Trade Secret version has been served on the governmental agencies that are parties in Docket No. E002/CN-13-606. If you have any questions regarding this filing, please contact me at james.r.alders@xcelenergy.com or (612) 330-6732.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY TO INITIATE A COMPETITIVE RESOURCE ACQUISITION PROCESS

DOCKET NOS. E002/CN-12-1240 AND E002/CN-13-606

COMPLIANCE

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Compliance filing as required in the Commission's May 23, 2014 ORDER in Docket No. E002/CN-12-1240. In this filing, we provide the following information required in the Commission's Order:

- A status report regarding changes in the Company's resource needs, including those resulting from changes in MISO's reserve requirements by October 2014;
- Draft Power Purchase Agreements with Calpine and Invenergy, and price terms for Black Dog Unit 6, so that the Commission can determine which of these project(s), if any, best addresses the Company's overall system needs identified in this proceeding and the Commission's March 5, 2013 Order in E002/RP-10-825; and
- A draft Power Purchase Agreement (PPA) with Geronimo Energy, for Commission review to ensure that the negotiated terms for the Aurora solar project are consistent with the public interest.

As we explain below, changes in our expected capacity needs suggest that our resource need has softened and the Commission may want the Company to defer selection and seek additional flexibility from all bidders. Below, we outline a proposed path forward that we believe will ensure that the Company has adequate capacity resources to meet our customers' needs, and acquires adequate resources timed cost-effectively with our expected needs. Additionally, in recognition of the unique timing issues surrounding solar resources, we offer options for the Commission's consideration with respect to the acquisition of these resources.

OVERVIEW

We have spent the summer negotiating contracts and developing pricing terms with the parties consistent with the Commission's Order, which we provide with this filing. However, based on our updated resource need assessment, we believe it would be beneficial to our customers to delay the addition of any thermal resources to our system. Instead, we recommend the Commission afford us the opportunity to work with Calpine and Invenergy to renegotiate PPAs with pricing to reflect in-service dates ranging from 2019-2021 and similarly refresh our Black Dog 6 self-build proposal.

We would then bring the revised agreements and our Black Dog 6 pricing terms, along with any new resource need information, back to the Commission by May 1, 2015. We believe this will avoid adding unnecessary thermal resources to our system – and significant costs for customers.

With respect to solar, however, given the expected step-down of the Investment Tax Credit (ITC) at the end of 2016, we believe a different approach – and some urgency – is needed. As we discussed in our September 12, 2014 Status Update in our Solar RFP proceeding (Docket No. E002/M-14-162), we received competitive pricing on a range of solar proposals, and believe the Commission would benefit from a wholistic look at the addition of solar resources to our system. Thus, we believe the Commission's public interest determination for the Aurora solar project in this CAP proceeding could be informed by the PPAs we develop through the Solar RFP process.

We expect to submit the PPAs that result from our Solar RFP process in mid-October 2014, and believe it will be in the best interests of our customers for the Commission to consider a broad range of proposals in deciding the best solar resources to add to our system beginning in 2016. For example, given the pricing and the potential expiration of the ITC, the Commission may decide the Company should add more than it minimally needs to meet its Solar Energy Standard compliance requirements.

The remainder of our filing is organized as follows:

- *Background*, which provides an overview of relevant procedural information.
- *Updated Resource Need Assessment*, providing the results of our current resource

need assessment and discussing key issues that have changed since the Commission determined the Company's 2017-2019 resource need.

- *Resource Need Summary,* discussing the results and conclusions of our resource need assessment.
- *Thermal Resource Agreement Terms,* outlining the terms of the Calpine and Invenergy agreements and Black Dog 6 pricing and the Company's recommendation for acquisition of thermal resources.
- *Solar Resource Acquisition,* outlining the terms of the Geronimo agreement, and discussion and options for the Commission to consider for meeting the Company's immediate solar resource needs.

A. Background

On November 21, 2012, the Commission initiated Docket No. E002/CN-12-1240 to solicit proposals from project developers to meet the revised assessment of the Company's resource needs. On March 5, 2013, in the Company's Integrated Resource Plan proceeding in Docket No. E002/RP-10-825, the Commission issued an order declaring a demonstrated need for an additional capacity of 150 MW by 2017, increasing up to 500 MW by 2019.

In April 2013, bids to meet the identified need were submitted to the Commission, and in June 2013, the Commission referred the matter to a contested case proceeding. On December 31, 2013, the Administrative Law Judge issued his FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION. The Commission considered the matter March 25 and 27, 2014, and on May 23, 2014 issued its ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES.

The Commission's May 23, 2014 ORDER required the Company to negotiate draft PPAs for acquiring new supply resources with Geronimo Energy, Calpine Corporation, and Invenergy Thermal Development – and to develop price terms for its own Black Dog Unit 6 – and submit the terms for Commission approval no later than September 23, 2014. The Order also required the Company to submit status updates by October 2014 and October 2015 regarding any changes in the Company's resource needs.

B. Updated Resource Need Assessment

In the Commission's May 23, 2014 Order, the Commission found that the future adequacy, reliability, and efficiency of power available to the Company, its customers, and the people of Minnesota and neighboring states, depends upon a prudent assessment of need.[1] The Commission also acknowledged that there were several areas of uncertainty in the record regarding the Company's resource needs in the 2017-2019 timeframe, including customer demand, evolving MISO reserve requirements, and possible changes in MISO's accreditation of demand response resources.

In this section we provide an updated customer demand forecast, and discuss each of these issues, which contribute to our current assessment of our capacity need. In summary, we believe our capacity need has changed from an *increasing need* to a *flat capacity surplus* through as late as 2023, which we believe supports a delay of two years or more in adding any new capacity resource to our system.

The amount of generating capacity needed to meet our customers' electrical demand is determined by considering a combination of factors. The analysis starts with the forecast of our customers' peak demand for electricity. To that, a Reserve Margin is added to reflect the utility's contribution to the region's pool of generation that can respond to unexpected equipment outages. The combination of Peak Demand and Reserve represent the Company's total Generating Capacity Obligation, which is then compared to the generation available to meet the obligation, as shown below:

> *Peak Customer Demand Forecast* **plus** *Reserve Margin* **equals**
> *Total Generating Capacity Obligation*

> *Total Generating Capacity Obligation* **minus**
> *Demand Response Capability* **and**
> *Existing Generation Capacity as Measured by UCAP* **and**
> *Generation Adjustments* **equals**
> *Net Generating Capacity Obligation/Surplus*

In our analysis, our Demand Response Capability is treated as a resource that can be used to meet a portion of Peak Demand, and we make adjustments for any known changes from our last analysis of available generating resources.

1. *Peak Customer Demand Forecast*

[1] Order at page 31.

Our most recent demand forecast that we discuss in this filing was prepared in August 2014 and reflects actual results through July. The demand forecast update we provided in September 2013 in this proceeding was from our Spring 2013 forecast, which included actuals through 2012. While we have been seeing stronger than expected sales in the recent past, our peak demand over the last two summers has not shown the same growth. In fact, our current forecast indicates a slight downward correction, projecting average growth over the 2017-2022 period to be less than 0.60 percent compared to the September 2013 update, which indicated average growth of 0.90 percent.

This lower expected growth rate in customer demand represents a 22 MW reduction in the forecasted median Peak Demand in 2017, growing to a 190 MW reduction by 2021, and a 388 MW reduction in 2024. As can be seen below, our current forecast update resulted in relatively modest changes in early years from the information we provided in September 2013:

Median Peak Demand Forecast
September 2014 compared to September 2013

(MW)	2017	2018	2019	2020	2021	2022	2023	2024
Sep 2013	9,500	9,590	9,676	9,770	9,859	9,950	10,029	10,100
Sep 2014	9,478	9,552	9,608	9,639	9,669	9,726	9,720	9,712
Difference	(22)	(38)	(68)	(131)	(190)	(224)	(309)	(388)

2. MISO Reserve Margin Requirements

The Company's Reserve Margin is the amount of generating capacity in excess of its forecasted Peak Customer Demand that the Company must maintain for regional electric grid reliability. Since 2013, MISO has determined resource adequacy by applying a percentage to each utility's customer demand at the time of the MISO system-wide peak demand to calculate a Reserve Margin. As reflected in the Commission's May 23, 2014 Order, the MISO Reserve Margin calculation is relatively new, and at the time of hearing in this proceeding, there was some reservation about whether MISO's coincident peak approach and associated calculation would remain stable. Since then, however, we have gained more confidence in the approach, and believe it represents a conservative estimate of Reserve Margin obligations.

In testimony in this proceeding, we described the process that led to our application of a 5 percent coincidence factor to the MISO peak to reflect the fact that, on average, customer demand on our NSP System is at 95 percent of its annual peak at the time of the MISO region-wide peak. MISO has since accepted our 5 percent coincidence factor, which we have reflected in the updated resource need assessment we present in this filing.

Another signal from MISO regarding its resource adequacy determination process is the continuing reduction in the Reserve Margin that utilities must include in their overall resource need determination process. In our Resource Plan, and previously in this proceeding, we used the most current MISO reserve calculation, which was 7.39 percent for the 2012/2013 planning period. The rate for planning year 2014/2015 is 7.3 percent, and MISO recently set the rate at 7.1 percent for planning year 2015/2016, which is what we have used in this updated need analysis.

The trend of reductions in the amount of generation held in reserve in percentage terms is consistent with the expansion of the MISO region and increase in the pool of resources that can be shared to respond to unexpected generation outages. Recent MISO analysis also indicates that Zone 1 of the MISO system has substantial import capability from other parts of MISO.

We understand that there is continuing discussion of Reserve Margin calculations, and that there could be further reductions as new transmission infrastructure strengthens connections among MISO's sub-regions.[2] Overall, MISO is getting more confident with its load forecasting, including non-coincident peak, as well as its Reserve Margin needs. In fact, MISO's most recent *Loss of Load Probability Analysis Report* projects a 6.5 percent Reserve Margin percentage for the 2024/2025 planning year.

Xcel Energy's Reserve Margin obligation utilizing the 5 percent coincidence factor and the 7.1 percent reserve value results in approximately a 640 MW Reserve Margin obligation.[3] The impact of applying the coincidence factor and updated reserve percentage to our updated resource need assessment is a reduction in our capacity obligation of 217 to 267 MW over the 2017-2019 period, from the September 2013 resource need information we provided in this proceeding. We recognize that there can still be evolution of these specific numbers, but given MISO's acceptance of both

[2] We are aware that MISO and the OMS provided FERC with a resource adequacy update regarding a survey that assessed the capacity needs of the MISO footprint in the short-term. The survey shows that Zone 1, which includes Minnesota, is projected to have a small capacity surplus in 2016. The update also acknowledges that there are capacity deficiencies in other Zones, but there are resources planned to be placed in-service to address those deficiencies. See FERC Docket AD14-17-000 (*Update on MISO 2016 Resource Adequacy Forecast*, September 18, 2014).
[3] Obligation values are reflected in terms of UCAP.

values, and their projected future Reserve Margin, their use now represents our most likely assessment of future need.

3. *Capacity Need Summary*

Our updated Customer Peak Demand forecast and the result of the MISO capacity resource adequacy determination calculation results in our overall Total Generating Capacity Obligation. In 2017, we anticipate an obligation of just over 9,640 MW; by 2020, our obligation estimate increases to just over 9,800 MW.

4. *Demand Response Capability*

Demand Response, often referred to as *load management*, is a customer resource that evolves with market conditions. These programs encourage customers to reduce loads when called upon in return for lower electric rates or bill credits. Although these loads can vary based on customer activity and other external forces, we are confident that we can provide the forecasted load reductions in the 2017-2020 time period as indicated in our Resource Need Assessment outlined in Section C below.

We have based our Demand Response projections on the fact that we have a large portfolio of load management resources in Minnesota built through decades of customer engagement and program development. While there is some uncertainty regarding the rules and how Demand Response will be valued in the future, we will continue to work with MISO to get the rules right – and with our customers, to verify our programs provide expected load relief, and to deliver new program choices that grow our future Demand Response resources.[4]

5. *Existing Generation Capability*

In MISO's resource adequacy analysis, it assigns a production capability value (UCAP) to each generating unit, with generating units having higher availability contributing more to the resource adequacy than units with lower availability history. However, MISO's typical 3-year rolling average approach has the effect of penalizing units that have experienced extended repair outages such as Sherco 3 and Black Dog 5-2.

[4] We note that on May 23, 2014, the D.C. Circuit Court of Appeals vacated FERC Order 745, rejecting FERC jurisdiction over demand response pricing, which may slow the of pace of any change to the current rules. *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C.Cir.2014).

To gain a longer-term perspective and better sense of what unit availability values will look like three or more years from now, we have used a value based on each unit's median availability over the last five years. The longer time horizon provides a better indication of future generating unit availability, since it is not skewed by an abnormal repair outage. This provides a more realistic view of our resource capability when looking at the need for future resource acquisitions.

6. *Other Factors Affecting our Need*

Resource need assessments are always dynamic, and we have attempted to approach our updated need assessment with a conservative view by not including some of the potential demand reductions and other generation additions that could conceivably occur in the 2017-2020 timeframe. For example, we have become aware that we may have customers adding both incremental industrial load and onsite generation resources that together may reduce our net capacity obligation. We have not attempted to incorporate adjustments for these potential changes at this time. However, we may be in better position next Spring to know whether any material adjustments are necessary.

C. Resource Need Summary

We present our updated Resource Need Assessment below. In summary, our analysis indicates that we will have surplus capacity resources – over-and-above our MISO Reserve Margin – of approximately 250 MW in 2017, 175 MW in 2018, and nearly 100 MW in 2019. This changed assessment is the result of very modest changes in the Customer Demand forecast, but primarily greater confidence in the MISO resource adequacy paradigm.

Resource Need Assessment - Summary
September 2014

	2017	2018	2019	2020	2021	2022	2023	2024
Peak	9,478	9,552	9,608	9,639	9,669	9,726	9,720	9,712
Coincident Peak adjustment	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Capacity Obligation	9,643	9,719	9,776	9,807	9,838	9,896	9,890	9,881
Coal	2,414	2,414	2,414	2,414	2,414	2,414	2,414	2,395
Nuclear	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Gas	3457	3457	3446	3,293	3,293	3,293	3,293	3,137
Wind, Hydro, Bio	1,253	1,230	1,204	1,203	1,433	1,425	1,385	1,317
Solar	109	115	121	127	129	128	128	127
Load Management	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101
Resources	9,897	9,892	9,872	9,736	9,979	9,981	9,953	9,720
Net Resource Surplus (Deficit)	***254***	***173***	***96***	***(71)***	***141***	***85***	***63***	***(161)***

During the negotiation of Power Purchase Agreements with the parties and prior to our completion of our Customer Demand forecast update, it became apparent that, due to the passage of time, bidders were no longer able to meet a 2017 in-service date with their projects. As a result, we began to investigate whether there may be any short-term capacity enhancements available. We discuss below two short-term resources that we identified could be used as tools to further strengthen our resource adequacy position if needed.

Manitoba Hydro. Xcel Energy and Manitoba Hydro are parties to three separate power supply agreements that terminate in April 2025. These agreements, in aggregate, provide the Company with over 700 MW of accredited summer generation capacity for years 2015-2020, increasing to over 800 MW for years 2021-2025. One of these agreements is an exchange of generating capacity. In the arrangement, Manitoba Hydro provides the Company 350 MW of generation capacity during the summer; in exchange, we provide 350 MW to Manitoba Hydro in the winter when they experience peak demand.

This exchange is designed to make more efficient use of generation capacity that exists on each party's system and is available during non-peak portions of the year when each System's demand for power is low. We are currently in discussions with Manitoba Hydro to increase our diversity exchange by approximately 75 MW.

This incremental 75 MW exchange would utilize existing transmission paths. While the exact term of the additional 75 MW capacity exchange is still being negotiated between the parties, it is contemplated that it will cover years 2016 through 2019.

Since the addition of 75 MW to our system in the summer would be part of an exchange of capacity, we do not anticipate it would result in any incremental cost to our customers. We will be continuing discussions with Manitoba Hydro over the next few months to see if we can add this short-term addition to our system.

Blue Lake. We have also investigated the remaining lives of some of our older peaking units. As part of past resource need assessments we have assumed four of our older peaking units, Blue Lake 1-4, will be retired in 2019. Blue Lake Units 1-4 are oil-fired peaking units that have been dispatched only a few times a year to provide energy during peak demand periods associated with extreme hot or cold weather conditions. These four units have combined capacity of 157 MW and can contribute approximately 153 MW toward MISO's resource adequacy determination.

We believe we can accomplish a short extension to their operating life, to 2023, with a minimal, if any, increase in current fixed and variable O&M, since the units are operated infrequently – and by the same staff operating other peaking units at the plant site. Further, we anticipate only minor improvements and repairs in order to extend the life of these units through the 2020-2023 period. We are planning boroscopic inspections to confirm the condition of the units. While at this time we have not identified any specific capital investments necessary to extend their operation, we have tried to be conservative and have assumed some incremental capital expense in the range of $3 to $5 million in the four years of additional operation.

As shown in the above Resource Need Summary table, with the addition of these potential resources, our capacity need assessment consistently shows surplus capacity through the mid-2020s. With the exception of one year, 2020, our need assessment has changed from an ever-increasing resource need to a relatively flat capacity surplus through 2023.

As we consider the results of this updated Resource Need Assessment, we believe these changes may cause the Commission to want to pause and collect additional information before committing to the addition of a new thermal resource on our system at this time. While we acknowledge there is always some uncertainty in resource need assessments, we believe we can substantially mitigate most potential short positions in this time horizon through use of the Manitoba Hydro and Blue Lake options. We provide below a view of how including these options would adjust our Resource Need Summary:

Resource Need Summary
(Including Short-Term Resources)
September 2014

	2017	2018	2019	2020	2021	2022	2023	2024
Net Resource Excess (Deficit) – Prior to Addition of Short-Term Resource Tools	*254*	*173*	*96*	*(71)*	*141*	*85*	*63*	*(161)*
Blue Lake 1-4 Life Extension				153	153	153	153	
Potential Manitoba Hydro Diversity Agreement	73	73	73					
Net Resource Surplus (Deficit)	**327**	**246**	**169**	**82**	**294**	**238**	**216**	**(161)**

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

Even though the analysis suggests we can forgo generation additions until at least 2020, if not longer, we believe a conservative approach continues to be in order. Rather than start a whole new resource acquisition process, we recommend that the Commission permit the Company to return to the bidders for renewed discussions regarding the timing of these resources.

We would work with bidders to refresh their proposals to reflect potential in-service dates in the 2019-2021 timeframe, as well as options to delay or cancel. We request that the Commission require the Company to report back in May 2015 with updated pricing for 2019-2021 in-service dates for all thermal PPAs and the Black Dog 6 unit if the Company believes it can provide greater benefit.

First year revenue requirements associated with the three natural gas proposals in this proceeding range from approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**[5] depending on which facility or combination of facilities is selected. We recognize the need to balance adequacy of supply with customer rate impacts. At this point, we do not see a need to add resources to our system perhaps until 2024. Because of this, our proposed approach of renegotiating with the identified best options for a slight shift in timing should provide sufficient safeguards to ensure we meet our capacity obligations if circumstances do not play out as we expect. However, if new generation can be avoided until the mid-2020s, it

[5] Trade Secret designation is based on the provisions of the October 1, 2013 Fifth Prehearing Order in this matter.

has the effect of completely eliminating a generating unit rather than just deferring the addition, consistent with state policy to minimize non-renewable resource additions.

Our proposal to bring back revised thermal PPAs also allows the Commission the opportunity to consider our next Resource Plan filing in January. That filing will provide more in-depth examination of our resource needs in the mid-2020s timeframe, will include the potential impacts of federal CO_2 regulations currently under development, and explore resource scenarios that can achieve Minnesota's greenhouse gas goals and comply with federal rules. With the Resource Plan filing in hand, we believe the Commission will have a better understanding of any interplay between the decisions that must be made in this docket and the important policy issues that will drive subsequent planning outcomes.[6]

D. Thermal Resource Agreement Terms

Over the summer, the Company has worked diligently with bidders to establish draft Power Purchase Agreements consistent with the Commission's May 23, 2014 Order. In this section, we present an overview of the draft PPAs we have negotiated with Calpine and Invenergy, and pricing terms for Black Dog 6. All PPAs are the result of the negotiation of terms designed to address and allocate project risks. We provide a discussion of each PPA, its risks, and how the PPA terms mitigate the risk.

1. *Calpine Mankato Energy Center Expansion*

Calpine proposed a 20-year PPA for the capacity of a 345 MW natural gas-fired combined cycle facility to be built at its existing 375 MW Mankato Energy Center combined cycle plant. Its bid contained a proposed kW-month price for capacity and MWh price for energy, as supplemented in the proceedings with respect to different commercial operation dates (CODs). The proposed capacity and energy prices escalate annually after the first year of operation. At hearing, Calpine initially proposed a 2017 COD, but upon request provided pricing information for CODs in 2018 and 2019.

Two principal changes in the structure of Calpine's proposal relating to COD and payment formulas developed in the course of negotiations, as follows:

[6] It is our goal to also provide the Commission and Minnesota stakeholders with information regarding the outcome of our North Dakota rate case as it relates to resource planning for the State of Minnesota and the NSP System.

(1) Calpine concluded that it could not construct its proposed facility in time for a June 1, 2017 COD, given: (1) the timing of the construction of the required transmission network upgrades for the facility's interconnection to be unconditional; and (2) the likely timing of the Commission's review and approval of the PPAs in this proceeding.

    The parties therefore negotiated a June 1, 2018 COD. Calpine will need a Commission-approved and Company-executed PPA in hand by April 1, 2015 to meet this date.

(2) Calpine's bid proposed that payment and other terms in the MEC II PPA would mirror the same terms in its existing, Commission-approved Mankato Energy Center PPA. In addition, the payment terms in the MEC II PPA include a dispatchability payment similar to a payment provision in the Mankato Energy Center PPA, although this was not included in Calpine's bid proposal.

    By using the existing Mankato Energy Center PPA payment provisions in the new PPA, the administrative burden associated with using two different payment calculations and billing processes for the two Mankato PPAs was avoided. It also avoids the risk that unforeseen differences in the payments made and received under different calculation formulas for the two PPAs could have unintended consequences on how the parties choose to schedule, operate, and properly calculate payments for each facility.

    However, the impact of adding the dispatchability payment and using the facility availability formula from the existing Mankato Energy Center PPA resulted in a marginal increase in the aggregate capacity payments to Calpine when compared to the capacity payments calculated pursuant to the Company's Model PPA.

The PPA addresses risks in the following areas:

Delay/Termination of the PPA based on need. Consistent with the Commission's order, Calpine provided options to delay or terminate its PPA in the event the Commission considers delay or termination prudent in light of new information about the Company's need for the PPA. The Company may delay the facility's COD from 2018 to 2019 subject to the increased capacity and energy prices associated with the new COD, and must also pay for Calpine's demobilization and re-mobilization costs. The Company may also terminate the PPA, paying Calpine for its unrecovered costs, as well as a breakage fee in addition to the unrecovered costs. Total termination fees could be substantial as shown in the PPA, provided as Trade Secret Attachment A.

Transmission Interconnection Costs. Calpine's proposal was that the Company pay for all transmission costs to interconnect the MEC II Facility to the grid. In the course of the proceedings, Calpine estimated that these costs could run from $650,000 to $1.5 million. While the Company sought to cap the Company's exposure for transmission interconnection costs at Calpine's estimate, Calpine was unwilling to agree given its uncertainty of the total amount of such costs.

Capacity Accreditation Risk. It appears there are transmission network upgrades that must be made before MISO can accredit the MEC II Facility as a Capacity Resource available to the Company, and the completion schedule for these upgrades is beyond Calpine's control. As a result, Calpine would not agree to the MEC II PPA requiring a specific COD, given the uncertainties associated with the PPA requirement that Calpine must achieve MISO capacity accreditation of the MEC II Facility. The Company therefore agreed to Calpine's proposal that it may elect to delay COD by one year upon timely notice to the Company that Calpine cannot achieve accreditation by COD. This allows the Company to obtain from another source the capacity credit it needs for the year the PPA is delayed, although the cost of the capacity credit will be subject to the prevailing market conditions. Absent such timely notice, Calpine must achieve accreditation by COD, and failure to do so is an Event of Default subject to specific cure provisions designed to keep the Company whole in all events.

Environmental Risk. Calpine proposed that the Company be liable under the MEC II PPA for all costs resulting from future regulation of all types of emissions. The Company strongly objected to its customers incurring these unknowable costs, and Calpine accepted the Company's position that it will only accept conditional risks from the regulation of carbon emissions as stated in its Model PPA.

Financial Risk. The Mankato Expansion PPA establishes a pre-COD and post-COD security fund to protect the Company generally from the range of financial risks associated with the PPA. The Company also negotiated a provision requiring Calpine upon completion of the facility to obtain a subordinated mortgage on the facility for the benefit of the Company.

Construction/Operational Risk. The Company negotiated the payment of liquidated damages for each day that Calpine fails to meet COD for the MEC II Facility due to reasons other than its failure to achieve MISO accreditation of the facility as a

Capacity Resource. In addition, the MEC II PPA includes other protective measures such as specific performance, step-in rights, actual damages, and termination. The Company also accepted Calpine's proposal that it be allowed to provide energy from an alternative generation source post COD in the event that more than 50 MW of the capacity of its new MEC II Facility becomes unavailable due to a forced outage. This holds the Company harmless from a shortfall in meeting its energy needs in the face of a significant outage of the MEC II Facility.

Adding the MEC II Facility to the NSP System in June 2018 would result in the addition of approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** of revenue requirements in 2018 and **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in 2019.

We provide a copy of the Calpine PPA as Trade Secret Attachment A.

2. *Invenergy Cannon Falls Expansion*

Invenergy proposed a 20-year PPA for the capacity of a 179 MW combustion turbine peaking unit added to its existing 357 MW simple cycle plant site at Cannon Falls, Minnesota. The monthly payment structure was based on proposed price per kW-month for capacity, price per MWh for energy, and price per turbine start, each escalated annually after the first year of operation.

Invenergy's pricing was supplemented in the course of the proceedings to reflect different CODs. Invenergy initially proposed a June 1, 2016 COD, but upon request during the course of the proceedings provided pricing information for a 2017 COD, when it was anticipated Xcel Energy's need would begin, as well as for 2018 and 2019 CODs.

There are two principal changes in the structure of the Invenergy PPA, relating to its initial start date and the amount of capacity provided under the PPA, as follows:

(1) As was the case with Calpine, Invenergy concluded that it could not construct its proposed CT facility in time for a June 1, 2017 COD, given the timing of required transmission network upgrades for the Facility's interconnection to be unconditional, and the likely timing of the Commission's review and approval of its PPA with the Company. The parties therefore negotiated a June 1, 2018 COD. Invenergy will need a Commission-approved and Company-executed PPA in hand by April 1, 2015 to meet the June 1, 2018 COD.

(2) The second change is the result of the COD being moved two years later than the June 1, 2016 COD Invenergy originally proposed. Because of this delay, Invenergy is no longer planning on using the 179 MW CT it had in stock as its CF II Facility; it will use that CT instead for another Invenergy project that needs to be in service before 2018. Invenergy now plans to add a new 209 MW GE Turbine 7FA.05 at its CF II Facility.

The PPA addresses risks in the following areas:

Delay/Termination of the PPA based on need. In response to the Commission's request for PPA delay and early termination options, Invenergy will allow the Company to delay the CF II Facility's 2018 COD to 2019. While the Company will pay the higher capacity and energy prices associated with the 2019 COD, there is no additional payment or fee associated with the delay. The Company may also terminate the CF II PPA subject to an early termination fee.

Transmission Interconnection Costs. Invenergy's proposal included a specific dollar amount for anticipated costs to interconnect its new CF II Facility to the transmission network, with any costs over that amount passed onto the Company and its ratepayers for collection. In the course of negotiations, Invenergy abandoned its proposal that the Company cover any of the project's transmission and interconnection related costs beyond the amount included in its PPA pricing.

Capacity Accreditation Risk. As with Calpine's project, Invenergy's addition of an additional CT peaker to its existing Cannon Falls plant site requires the completion of certain transmission network upgrades before it can be accredited as a Capacity Resource by MISO. Invenergy has no control over the schedule for completing those upgrades, and as a result the Company negotiated the same provisions with Invenergy that it did with Calpine to keep itself whole in the event that Invenergy cannot obtain capacity accreditation for its CF II Facility by COD.

Environmental Risk. As was the case with Calpine, Invenergy agreed to the Company's position that it would only accept the conditional risks associated with the future regulation of carbon emissions.

Financial Risk. The Company negotiated pre-COD and post-COD security fund amounts to protect the Company generally from the range of financial risks associated with the Invenergy CF II PPA.

Construction/Operational Risk. The Company negotiated the payment of liquidated damages for each day Invenergy fails to meet COD for its CF II Facility for reasons other than failure to achieve accreditation. The CF II PPA also includes other protective measures such as specific performance, step-in rights, actual damages, and termination.

Invenergy also proposed in the course of negotiations to increase the current oil storage at the Cannon Falls plant by 50 percent at no cost to the Company. The increase will allow the entire site to maintain its current fuel oil run capability of 28 consecutive hours after the addition of the CF II Facility.

Adding the Invenergy Cannon Falls facility to the NSP System in June 2018 would result in the addition of approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** of revenue requirements in 2018 and **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in 2019.

We provide a copy of the Invenergy PPA as Trade Secret Attachment B.

3. Xcel Energy Black Dog 6 Proposal

Xcel Energy proposed a peaking unit, nominally a 215 MW combustion turbine, located within the power house at the Black Dog plant site in Burnsville. Only minor modifications to the existing 115 kV switchyard will be required to connect Black Dog 6 to the transmission system, and no upgrades are required to the 115 kV transmission system. Unit 6 will increase the plant's high pressure natural gas need, for which the Company plans to conduct a competitive process for supply to the plant.

We provided capital cost estimates for Black Dog 6 and its associated transmission interconnection for 2017, 2018, and 2019 in-service dates. As is the case with other bidders, due to the passage of time, we are no longer able to meet a 2017 in-service date. Our capital cost estimates for 2018 or 2019 in-service dates have not changed. However, to meet a 2018 in-service date, we will have to make commitments to major equipment soon, with generally a three-year lead time. Thus, like other bidders, cancellation after those commitments are made would result in sunk costs. To be clear, our proposal is to recover all prudently-incurred sunk costs if the project is cancelled after authorized to proceed.

In its May 23, 2014 Order, the Commission directed the Company to present terms of a similar nature to those of other bidders. Furthermore, the Order indicates that bidders should be held to the parameters of their bids that ratepayers should not be subject to costs higher than those bid, but that bidders should be able to retain any savings if actual costs are below what was presented.

In compliance with the Commission's Order, we propose the capital cost estimates presented in our initial April 2013 filing for a 2018 or a 2019 in-service date for Black Dog 6 be the basis for cost recovery. If the actual capital cost of Black Dog 6 is higher than the estimate presented, only the estimate and allowance for funds used during construction (AFUDC) associated with the estimate would be placed in rate base. If the actual cost of the project is less than the estimate, the full capital cost estimate along with AFUDC associated with actual incurred costs will be put in rate base. We would create a regulatory asset on our books to recognize the difference between actual cost and that included in rate base.

4. *Thermal Resource Recommendations*

As we have outlined, a number of changes have occurred since the Commission ordered the Company to fill a need of 150 MW in 2017, increasing to 500 MW in 2019. In summary, instead of a need during the 2017-2019 timeframe, we are forecasting a relatively steady surplus as outlined in the Resource Need Summary section of this filing. In light of these changes and opportunities, we recommend that the Commission permit the Company to return to the bidders for renewed discussions regarding the timing of these resources.

We request that the Commission require the Company to report back to the Commission in May 2015 with updated pricing for delayed in-service dates to address a potential need in the 2019-2021 timeframe for all thermal PPAs and the Black Dog 6 unit.

D. Solar Resource Acquisition

In its May 23, 2014 Order, the Commission required the Company to negotiate a draft PPA with Geronimo Energy, and submit it to the Commission to ensure the negotiated terms are in the public interest. We provide the Geronimo PPA as Trade Secret Attachment C to this filing, and discuss its terms below. In this section, we additionally discuss how the Geronimo PPA in this proceeding may interact with the PPAs we are negotiating in our Solar RFP effort.

We believe our customers would benefit from the Commission taking a wholistic look at the addition of solar resources to our system – and therefore, considering

Geronimo's Aurora solar project in this CAP proceeding alongside the Solar RFP PPAs we will submit to the Commission in mid-October.

1. *Aurora Project Summary*

Geronimo proposed a 20-year PPA for up to 100 MW of nameplate capacity from distributed solar facilities, ranging in size from 2 MW to 10 MW and located at up to 31 sites. Geronimo offered two pricing options: (1) a capacity price per kW-month escalating annually, and a per MWh energy price escalating annually; and (2) a bundled capacity/energy price per MWh escalating annually. Geronimo proposed a December 1, 2016 COD to ensure that its project would qualify for the 30 percent ITC, and proposed a modified solar energy PPA form that was used in a Request for Proposal process conducted by the Xcel Energy operating company Public Service Company of Colorado.

In the course of negotiations, the parties agreed upon using the Company's newly-developed Model Solar PPA with Geronimo's bundled per MWh capacity/energy price payment structure. To accommodate Geronimo's tax equity financing of the Aurora project sites, the parties negotiated a single PPA structure covering all sites (each site referred to as a "phase"), with the possibility of the PPA being split into a maximum of three separate PPAs as needed post-COD for tax equity financing purposes. As a result of this structure, each phase is treated as a separate project pre-COD, and the Company cannot terminate the single PPA because of any action or inaction of a particular phase that occurs prior to COD. The Company retains, however, pre-COD global default and termination rights for bad acts and defaults by Geronimo.

Geronimo has also modified the number of sites to 24, which range in size from 1.5 to 10 MW and total approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**[7]. The maximum nameplate capacity Geronimo may deliver under the PPA is capped at 100 MW, however, and Geronimo has the discretion to determine which of the sites it will bring to COD to deliver capacity up to the cap.

The PPA addresses areas of risk in the following ways:

Delay/Termination of PPA Based on Need. Geronimo's pricing depends in part on its phases qualifying for the ITC, and so the parties did not negotiate any delay or

[7] Trade Secret designation is based on the provisions of the October 1, 2013 Fifth Prehearing Order in this matter.

termination of the Geronimo PPA in response to changes in the Company's capacity need in the 2017-2019 time period.

Transmission Interconnection Costs. None of Geronimo's phases require interconnection to the transmission grid; they are all connected to the Company's system at the distribution level. Per its bid, Geronimo bears all distribution interconnection costs.

Capacity and Capacity Accreditation Risk. Geronimo offered up to 100 MW of nameplate capacity in its proposal. In the course of negotiations, the parties negotiated a scale of damage payments that escalates the further the aggregate MW level Geronimo brings to COD falls short of the 100 MW. In addition, Geronimo's failure to obtain 71 percent accreditation of the nameplate capacity it delivers results in damages for the period of the accredited capacity shortfall.

Environmental Risk. The Company will own all environmental and renewable energy credits.

Financial Risk. The Company negotiated pre-COD and post-COD security fund amounts to protect the Company generally from the range of financial risks associated with the Geronimo PPA. In addition, Geronimo takes all ITC qualification risks.

Construction/Operational Risk. The Company accepted Geronimo's proposal that completed phases can be recognized as having achieved COD in a 120-day window that begins September 1, 2016 and ends December 31, 2016. For each phase that fails to achieve COD by December 31, 2016, Geronimo will have the option to complete additional project phases, but will be required to pay liquidated damages until the phase achieves COD. The PPA also includes protective measures such as specific performance, step-in rights, actual damages, and termination.

Because of the likelihood that there will be some number of phases completed before the start of the COD window on September 1, 2016, Geronimo proposed the Company take pre-COD energy produced by a phase before that date. The Company agreed to take such energy at a price based on the prevailing market rate.

2. *Public Interest Approach to Solar Acquisition*

We believe that there are two public interest questions with respect to acquisition of solar resources in this CAP proceeding: (1) the amount of large-scale utility solar projects to acquire; and (2) whether the acquisitions should impact decisions regarding the public interest in this CAP proceeding. Regardless of the approach to the acquisition of solar resources the Commission chooses, the needed decisions are time-sensitive due to the significant reduction in the available ITC at the end of 2016.

a. Amount of Solar Resources

As to the amount of solar resources to acquire at this time, we indicated in our September 12, 2014 Solar RFP Update letter (Docket No. E002/M-14-162) that the banking rules for solar RECs required an addition of approximately 100 MW of utility-scale solar by 2020, compared to our previous estimate of 200 MW, which did not include the Commission's decisions regarding solar REC banking. The question of how much to acquire now is similar to previous wind acquisitions made to comply with the Renewable Energy Standard. The Commission needs to make some judgments about the amount of solar generation that we should add to our system in the 2016 timeframe. In making that determination, the Commission will be weighing the opportunity associated with the 30 percent ITC in 2016 compared to general trends in the declining cost of solar technology.

The 30 percent ITC will automatically reduce to 10 percent absent Congressional action for projects in-service beginning in 2017. Taking advantage of the higher ITC locks-in roughly a 20 percent price reduction by acting early – assuming no change in current law. Given the stagnation on the Production Tax Credit for wind resources in 2014, we believe there continues to be a real risk that certain of these tax benefits will not continue. On the countervailing side, we have seen dramatic decreases in solar power prices. If technology continues to improve at as rapid a pace as it has for the past five years, it may benefit customers to wait to add incremental resources.

While we think technology improvements are certainly not over, it will be difficult to replicate the magnitude of price decline going forward compared to what we have already seen. In order to comply with the Solar Energy Standard (SES) through at least 2024, we will need approximately 100 MW of retail and 100 MW of utility-scale resources. If approximately 100 MW are developed in customer-sponsored projects and community gardens, the remaining 200 MW becomes our non-banked target for utility-scale additions to our system.

However, the banking rules for solar RECs established by the Commission adds some flexibility to compliance. As we noted previously, we need to add only about 100 MW of utility-scale solar to maintain compliance through the mid-2020s. A more limited acquisition in 2016 might be warranted if substantial reductions in the cost of solar generation are foreseen by the mid-2020s. We currently lean toward fulfilling nearly all of our solar obligation with 2016 resources, because: (1) the uncertainty of any ITC extension; and (2) the certainty of the larger pre-2017 ITC benefit provides more certainty of selecting economic resources than awaiting potential technology improvements.

Therefore, we recommend targeting a total acquisition of utility-scale solar resources of approximately 150-200 MW to be added to our system by the end of 2016. This, together with the 100 MW of solar developed with customer-sponsored projects, will enable the Company to comply with the SES for the foreseeable future.

b. Mix of Solar Resources

There are different ways for the Commission to view the acquisition of solar resources. The first is to bifurcate the CAP proceeding's public interest determination from the Solar RFP response. The logic in this approach is that these are separate proceedings with different purposes – one for capacity planning and the other for solar compliance. Under this view, the processes, and thus the resources selected from them, could be viewed separately.

Another approach is to assume we will acquire a certain amount of solar resources to meet our compliance obligations under the statute. Under this approach, the Commission could recognize that although undertaken in different proceedings, the time period of the acquisitions will be overlapping and the nature of the resource – solar photovoltaics – makes them roughly identical from a system perspective. As such, acquiring the least-cost aggregate set of resources to meet compliance during this period would be in the public interest. In doing so, we acknowledge certain differences in contractual terms may exist, but we believe this could be considered in a wholistic comparison of solar resource options.

To assure no further disputes regarding confidentiality, we have marked the entire following discussion of our assessment of resource mix as Trade Secret. The October 1, 2013 Fifth Prehearing Order in this matter provides for Trade Secret designation. Additionally, certain material below is more restrictively marked as "Highly Sensitive Trade Secret Information – Third Party Confidential Information" consistent with paragraph 2(c) of the Fifth Prehearing Order, as this contains the confidential information submitted by certain participants in the Solar RFP conducted in Docket No. E002/M-14-162. Per the terms of this Order, this Third Party Confidential Information should not be disclosed in this docket to any party other than the governmental agencies.

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At this time, we recommend the Commission consolidate its solar acquisition public interest determinations and consider all the information available in both this CAP docket and the Solar RFP docket. When we submit the Solar RFP PPAs, the Commission will have the requisite information needed to make a public interest decision, and we will move forward with acquiring the resources selected by the Commission.

CONCLUSION

Xcel Energy provides updated resource need information, and the results of its negotiations with parties and development of pricing terms for its proposal to the Commission. We respectfully request the Commission to:

- Permit the Company to work with the thermal bidders, and on its Black Dog 6 proposal, to update terms and pricing that reflects in-service timing in the 2019-2021 timeframe; and
- Consider both the Aurora proposal for new solar resource additions to our system and PPAs from our RFP process when making public interest determinations in the two dockets.

Dated: September 23, 2014

Northern States Power Company

Respectfully submitted by:

/s/

JAMES ALDERS
STRATEGY CONSULTANT
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