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Direct Testimony and Schedules
Paul B. Johnson

Before the North Dakota Public Service Commission
State of North Dakota

Application of Northern States Power Company
for an Advance Determination of Prudence for a Power Purchase Agreement with
Mankato Energy Center, LLC for Approximately 345 MW of Combined-Cycle Gas
Generation

Case No. PU-15-_____
Exhibit___(PBJ-1)

Resource Need and Calpine Project PPA Testimony

February 13, 2015

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Table of Contents

I.	Introduction	1
II.	Resource Need	2
III.	Calpine Project PPA	11
IV.	Prudence of Calpine Project PPA	16
V.	Prudence of Proposed Resource Portfolio (Black Dog, Calpine, and Geronimo)	27

Schedules

Resume	Schedule 1

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Paul B. Johnson. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since July 2014 in the area of resource planning. In my current role, I am responsible for the direction and oversight of electric Resource Planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

My responsibilities include directing the development of resource plans, working closely with modeling to complete the analyses required for those plans. I also oversee the development and execution of Request for Proposals (RFP), the modeling for asset acquisition assessments, and provide long-term pricing guidance for purchased power negotiations. In addition, I lead the effort to provide resource analysis and planning guidance for regulatory filings, information requests needed by various departments, and NSP executives. My resume is provided as Exhibit___(PBJ-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the capacity resource need that is the basis for the Company's proposal to enter into a 20-year power purchase agreement (PPA) with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (Calpine

Project PPA), including the factors and analysis that went into determining the resource need. I also discuss the terms of the Calpine Project PPA, and our analysis of the PPA's costs and benefits for our ratepayers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company performs a rigorous analysis to estimate its resource needs many years into the future, using econometric and other assumptions and variables as a basis for its determinations. I identify in my testimony the challenges and difficulties in accurately assessing future generation capacity requirements, and provide the range of probable need we face based on the best available information we have. Company Witness Mr. Kurtis J. Haeger discusses in his Direct Testimony the variability in our demand forecasts that contributed to the the Company's determination of a capacity need of 150-500 MW by the end of the decade.

I then discuss the terms of the Calpine Project PPA, highlighting known risks and the steps taken to mitigate those risks. I also provide a detailed analysis of the costs and benefits of the PPA for our ratepayers to aid the Commission in its determination of the PPA's prudence.

II. RESOURCE NEED

Q. HOW IS THE COMPANY'S RESOURCE NEED DETERMINED?

A. The Company's assessment of resource need is based on three primary factors: (1) peak demand forecast; (2) required reserve margins; and (3) the maximum generation capability of existing resources. The peak demand forecast is based on an econometric model using a combination of variables, including weather-normalized native energy requirements and peak producing weather by month. The reserve margins are based on the reserve margin calculations used by the Midwest Independent System Operator, Inc., (MISO), the regional transmission organization to which the Company belongs. Finally, the maximum generation capability of existing resources is based on NSP System operational data.

In addition to analyzing peak demand, we also forecast our total annual energy requirements based on projected sales and transmission line losses, which includes the impact of Demand-Side Management on our total sales. This not only contributes to our assessment of a capacity need, but also allows us to assess the type of resource that will best meet our energy needs, that is, whether the best option in light of capacity and energy needs is the addition of a baseload, intermediate, or peaking resource to our system or some combination of those types of resources.

Q. WHAT IS THE COMPANY'S NEED?

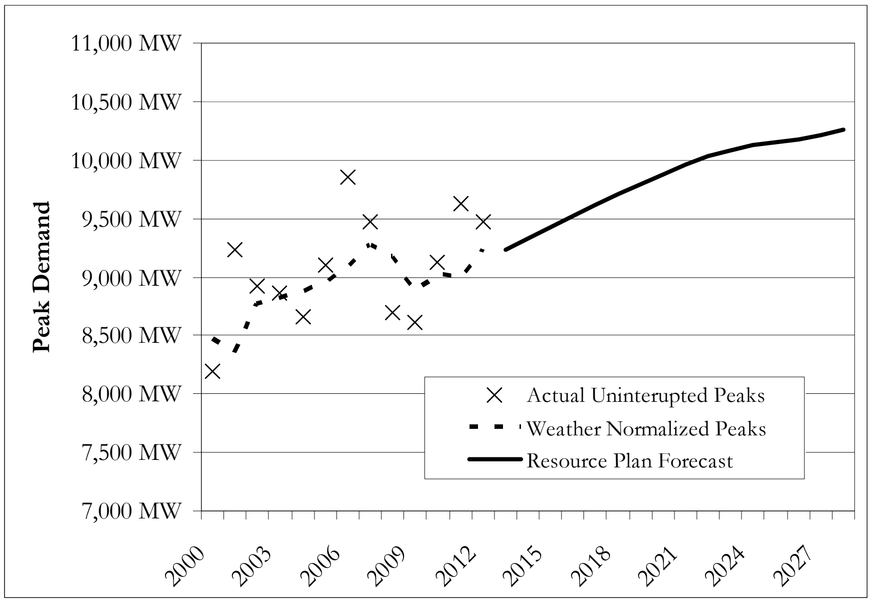
A. The Company's need is 150-500 MW by 2019/2020, based on our updated Fall 2011 forecast (Fall 2011 Forecast). This forecast updated the initial forecasting included in our 2010 Resource Plan. Augmented with information from the Company's Spring 2013 forecast, the Fall 2011 Forecast is the forecast that was used in our advance determination of prudence application for Black Dog Unit 6 and Red River Valley Units 1 and 2 (Case No. PU-13-194 (Gas CTs ADP Case)).

Q. PLEASE DESCRIBE THE COMPONENTS OF THE FALL 2011 FORECAST.

A. Figure 1 provides the Fall 2011 Forecast's peak demands. As shown in Figure

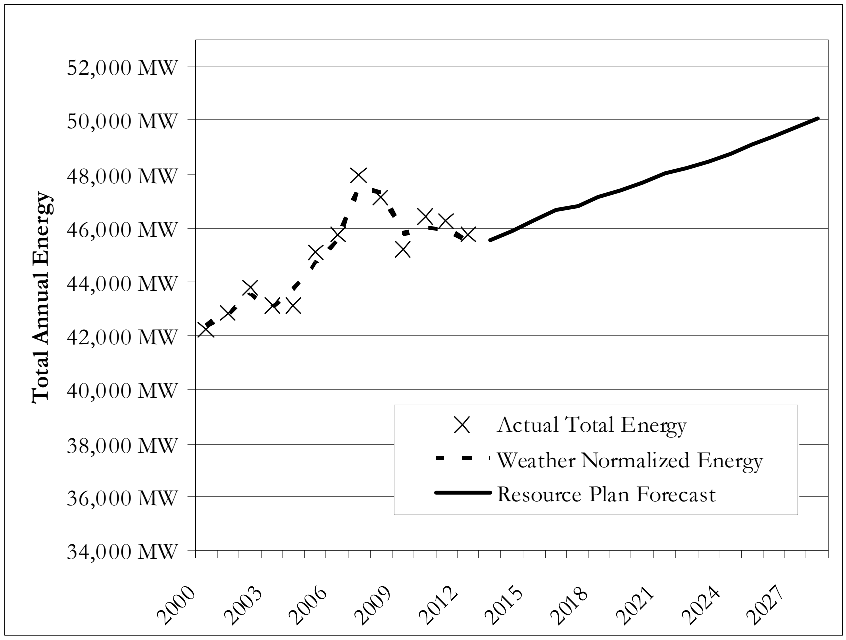
1, from 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

**Figure 1:
NSP Historic and Forecasted Peak Demand**



Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

Figure 2:
NSP Historic and Forecasts Total Annual Energy



Our Fall 2011 Forecast also took into consideration the reserve margin calculations specified by MISO using the criteria applicable at the time. MISO calculates the reserve margin percentage based on loss of load expectation (LOLE) studies that calculate how high the reserve margin must be to ensure that load will not have to be curtailed any more often than once in every 10 years. Comparing the load forecast plus reserve margin to the capacity ratings of Xcel Energy-owned resources plus purchased power, our system's forecasted capacity need is around 500 MW by 2019-2020, as shown in Table 1.

**Table 1:
System Capacity Need
(Fall 2011 Forecast)**

	2015	2016	2017	2018	2019	2020
Peak Forecast	9,428	9,524	9,613	9,708	9,799	9,881
x 1+RM%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
= Total Obligation	9,786	9,885	9,977	10,076	10,170	10,255
Resources	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Coal	2,331	2,331	2,331	2,331	2,331	2,331
Nuclear	1,610	1,610	1,610	1,610	1,610	1,610
Gas	3,476	3,534	3,437	3,424	3,424	3,424
Renewable	1,288	1,289	1,287	1,238	1,212	1,213
Other	92	-	-	-	-	-
Load Management*	1,145	1,153	1,157	1,153	1,149	1,145
Total	9,943	9,917	9,823	9,757	9,727	9,724
Long (Short)	**157**	**32**	**(154)**	**(319)**	**(443)**	**(532)**

* Includes reserves

As shown in Table 1, our Fall 2011 Forecast identified a capacity need of 153 MW in 2017, growing to 532 MW in 2020.

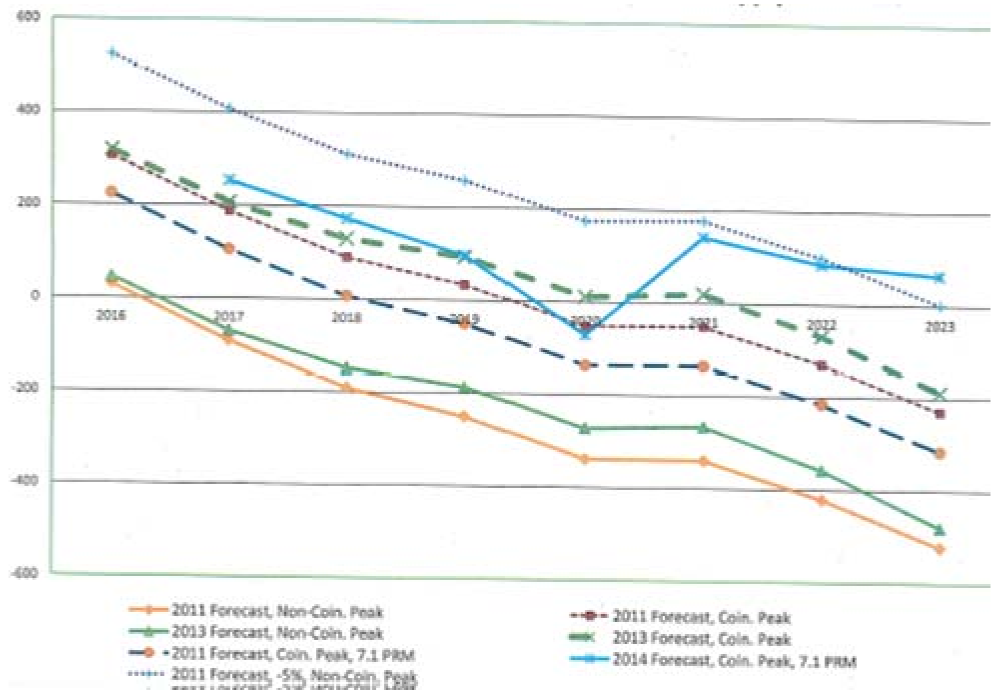
Q. PLEASE DESCRIBE THE UNCERTAINTY RELATING TO CHANGES IN HOW MISO CALCULATES RESERVE MARGINS.

A. The way MISO calculates the generation reserve margins necessary to ensure system reliability has been subject to on-going change. Starting in 2013, MISO's reserve margin calculation for individual utility systems will change to reflect the utility's peak demand *at the time of the region's peak*, rather than the utility's own peak. The Company's demand at the MISO peak has varied substantially, and has not been coincident with MISO's in five of the last eight summer seasons – averaging approximately five percent lower than our own peak.

Because our peak has not been coincident with MISO's, this methodology change reduces our reserve obligation. For 2013, the Company's reserve margin was approximately 200-300 MW lower than what we used in 2010 Resource Plan analysis. Relatively small changes in coincidence factors, combined with adjustments in MISO's UCAP capacity calculations and adjustments in MISO's annual loss of load expectation calculations, can swing reserve requirements on our system measurably. However, it is not clear at this time how reserve calculations might change between now and the 2017-2019 time period for which we currently have identified resource needs.

Figure 3 below illustrates the impact of this uncertainty by applying the coincident and non-coincident methodologies to various demand forecasts considered during our 2010 Resource Plan proceedings. The figure shows that very small changes can result in material swings in the required amount of capacity.

**Figure 3:
Impact of Coincident and Non-Coincident Peak Methodologies on Resource Plan Need Forecasts**



Source: Department of Commerce, Docket No. E002/CN-12-1240 (Dec. 10, 2014)

Q. WHAT IS THE MOST RECENT FORECAST OF THE COMPANY'S NEED IN ITS 2015 RESOURCE PLAN?

A. The Company's recently filed Resource Plan shows a modest amount of excess capacity (between 1 and 2.5 percent) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains a small amount of excess capacity by increasing our current Manitoba Hydro purchase with anticipated new capacity that is under development. In 2024, however, we again show a system deficit of 234 MW. This load balance profile suggests that we are at risk of capacity deficits beginning in 2019 and 2020 if our projected loads change by even a very small amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our assumed supply portfolio is modest given that normal forecast variability can result in demand swings of 200 MW (2 percent) or more.

Q. WHAT ARE THE COMPANY'S OPTIONS FOR MANAGING THIS RISK OF CHANGES IN CUSTOMER LOAD FROM WHAT IS FORECASTED?

A. The normal variability we have experienced between load projections and actual results in recent years indicates it is appropriate to acquire additional generation as a hedge. While we recognize that we could potentially purchase short-term capacity from the MISO voluntary capacity market at then-prevailing rates for any capacity shortfall, we must also consider that existing and proposed retirements of baseload units in the MISO footprint may result in a shortfall of capacity across the footprint leading to higher capacity prices in the MISO voluntary short-term capacity market. Prudent planning includes balancing the risk of exposure to the capacity market in the next five years against the cost of building additional capacity in the 2019/2020 time-frame, which will be necessary by 2024 in any event.

Our 2015 Resource Plan includes a scenario that reflects all of our currently contemplated resources. This includes: (1) the 98 MW accreditable capacity (187 MW nameplate) of the solar portfolio which is the subject of Case No. PU-14-810; (2) the 278 MW accreditable capacity (345 MW nameplate) of the Calpine Project PPA; (3) the up-to 71 MW accreditable capacity (100 MW nameplate) of the Geronimo Solar PPA; (4) the 207 accreditable capacity of the Black Dog 6 combustion turbine unit (215 MW nameplate); (5) a new short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated in our 2015 Resource Plan. If all of this contemplated new generation is deployed, it will result in a system surplus in the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685 MW in 2020) and address our resource need in 2024.

Table 2 provides a summary of this analysis on a system-wide basis:

Table 2:
System Capacity Forecast (MW)
(2014 Forecast)

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Long/(Short) (existing system)	177	142	242	91	8	0	231	182	163	(234)
Resources Approved by the MPUC	-	-	-	71[3]	278[4] 71[3]	207[5] 278[4] 71[3]	556[6]	556[6]	556[6]	556[6]
Proposed Additional Resources	-	73[1]	73[1]	98[2] 73[1]	98[2] 73[1]	98[2]	98[2]	98[2]	98[2]	98[2]
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171
Aggregate Additional Resources	-	73	73	243	551	684	773	773	803	855
Long/(Short) Position (assumes all additions)	**177**	**216**	**315**	**334**	**529**	**685**	**1,004**	**956**	**965**	**621**
Notes	1- Manitoba Hydro 75 MW additional capacity exchange (four years). 2- 187 MW Solar portfolio (98 MW accreditation) 3- Geronimo Solar Project PPA (2016 in-service; 2018 MISO accreditation) 4- Calpine Project PPA 5- Black Dog Unit 6 6- Geronimo PPA + Calpine Project PPA + Black Dog Unit 6									

Q. WHAT IS THE IMPACT IN NORTH DAKOTA?

A. We prepared a similar analysis showing the same information on a North Dakota load-allocated basis. The following Table 3 provides the output of that analysis:

Table 3:
North Dakota Allocated System Capacity Forecast (MW)
(2014 Forecast)

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ND as a Percentage of NSP System	4.94	4.99	5.01	5.05	5.08	5.13	5.19	5.22	5.34	5.38
Long/(Short) (existing system)	9	7	7	5	0	0	12	10	9	(13)
ND Allocation of Additional Resources	-	4	4	12	28	35	40	40	43	46
Long/(Short) (assumes all additions)	9	11	11	17	28	35	52	50	52	33

This shows that on a North Dakota allocated basis, there is no statistical excess capacity in 2019 and 2020. While the number increases again in 2021 due to the addition of new capacity from Manitoba Hydro, it is appropriate to plan the system to include additional capacity that addresses the 2019 and 2020 'pinch point' and remains available in 2024 when we begin to experience forecasted capacity deficits.

III. CALPINE PROJECT PPA

Q. PLEASE DESCRIBE THE CALPINE PROJECT PPA?

A. The 20-year PPA will provide approximately 345 MW (nameplate) of capacity and associated energy to our system from a new natural-gas combined-cycle unit to be added to Calpine's existing 375 MW Mankato Energy Center (MEC), located in Mankato, Minnesota. The new 345 MW CC unit (with an accredited capacity of 278 MW) will be incorporated into the existing footprint of MEC. The Company currently has a 20-year PPA with Calpine for all of the capacity and associated energy produced from the existing 375 MW CC unit at MEC, which expires in 2026.

Q. WHAT ARE THE PRINCIPAL TERMS OF THE CALPINE PROJECT PPA?

A. The PPA has a kW-month price for capacity and MWh price for energy. The proposed capacity and energy prices escalate annually after the first year of operation. We anticipate that the new C unit at MEC will achieve commercial operation in 2018 or 2019. Adding the resource 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.

The payment and other terms in the PPA generally mirror the same terms in the Company's existing MEC PPA with Calpine. By using the existing MEC PPA payment provisions in the new Calpine Project PPA, the administrative burden associated with using two different payment calculations and billing processes for the two 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.

Q. PLEASE DESCRIBE THE RISKS OF THE PPA.

A. The Calpine Project PPA had risks with respect to (1) potential need to delay or terminate the PPA; (2) transmission interconnection costs; (3) capacity accreditation; (4) environmental costs; (5) financial security; (6) construction and operational issues; and (7) governmental/third-party authorizations and approvals.

Q. PLEASE DESCRIBE HOW THE COMPANY MITIGATED THE DELAY/TERMINATION RISKS?

A. The Company negotiated options to delay or terminate its PPA in the event future circumstances warrant doing so. In the event it is deemed prudent to delay the PPA, the Company may at its discretion 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 Exhibit___(KJH-1), Schedule 2.

Q. WHAT IS THE RISK WITH RESPECT TO TRANSMISSION INTERCONNECTION COST?

A. The PPA reflects Calpine's proposal that the Company pay for all transmission costs to interconnect the expansion Facility to the grid. Calpine has estimated that these costs will run from $650,000 to $1.5 million, and the Company has agreed to accept the risk of such costs.

Q. WHAT IS THE CAPACITY ACCREDITATION RISK AND HOW HAS IT BEEN MITIGATED?

A. It appears there are transmission network upgrades that must be made before MISO can accredit the expansion capacity as a Capacity Resource available to the Company, and the completion schedule for these upgrades is beyond

Calpine's control. The Company 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.

Q. PLEASE DESCRIBE THE COMPANY'S MITIGATION OF THE RISKS ASSOCIATED WITH ENVIRONMENTAL COSTS.

A. Calpine proposed that the Company be liable for all costs resulting from future regulation of all types of emissions. The Company strongly objected to its customers incurring these unknown costs, and Calpine accepted the Company's position that it will only accept the conditional risk of carbon emission regulation consistent with the Company's assumption of that risk as stated in the Company's model PPA used to guide negotiations.

Q. HOW DOES THE PPA MITIGATE THE FINANCIAL SECURITY RISK OF THE PPA?

A. The Calpine Project 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 new CC unit to obtain a subordinated mortgage on the facility for the benefit of the Company.

Q. PLEASE DESCRIBE THE MITIGATION OF THE PPA'S CONSTRUCTION AND

OPERATIONAL RISKS.

A. The Company negotiated the payment of liquidated damages for each day that Calpine fails to meet COD for its new CC unit at the Mankato plant site due to reasons other than its failure to achieve MISO accreditation of the facility as a Capacity Resource. In addition, the 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 CC unit 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 new CC unit.

Q. WHAT ARE THE RISKS ASSOCIATED WITH GOVERNMENTAL AND OTHER THIRD PARTY APPROVALS AND AUTHORIZATIONS?

A. These risks include obtaining required governmental permits and approvals, obtaining required third-party contracts that are necessary for the project to be completed, and internal approvals of regulatory revisions of the PPA's terms. The PPA's "conditions precedent" provide a mechanism for terminating the PPA if these are not obtained. For Calpine, these conditions include obtaining an air permit, a site permit and interconnection agreement, and approval of the final PPA by the Calpine Board of Directors, all by specified dates.

For its part, the Company must obtain timely approval of the PPA from this Commission. The Company's obligation is to seek an approval order from the Commission no later than 15 business days after the execution of the

PPA, or the Company shall be deemed to have wiaved its right to seek such approval. The PPA provides that the Company may terminate the PPA if it has not received the requested approval from the Commission by April 1, 2015, but can delay the April 1 deadline to July 1, 2015 with the consequence that the PPA's commercial operation date is delayed until 2019.

IV. PRUDENCE OF CALPINE PROJECT PPA

Q. WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING THE PRUDENCE OF THE CALPINE PROJECT PPA?

A. The two principal factors are (1) whether the type, size, and timing of the Calpine Project PPA capacity is appropriate to meet the Company's identified need, and if so, (2) does it effectively meet that need at a reasonable cost. Mr. Haeger addresses our need in his Direct Testimony, and I address how the type, size, and timing of the Calpine Project PPA effectively meets that need at a reasonable cost.

Q. HOW DID THE COMPANY ANALYZE WHETHER THE TYPE, SIZE, AND TIMING OF THE CALPINE PROJECT PPA MEETS THE COMPANY'S NEED?

A. To ensure that sufficient resources were evaluated to cover the high end of potential capacity needs identified in our Fall 2011 Forecast, the Company used Strategist to model portfolios consisting of different combinations of the resource proposals submitted in the Minnesota competitive acquisition process (CAP) docket (MPUC Docket No. E002/CN-12-1240), ranging from 358 MW to 636 MW. These proposals represented peaking and intermediate resources.

In addition to the 345 MW combined cycle unit proposed by Calpine to be added in 2017 or 2018, we modeled the Company's proposal to add a single combustion turbine unit at its Black Dog plant in 2017, 2018, or 2019, and two combustion turbine units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019. We also modeled Invenergy Thermal Development, LLC's proposal to add a single 179 MW natural gas CT at its existing Cannon Falls, Minnesota plant, and two additional 179 MW CTs located at a new plant site near Hampton Corners, Minnesota. The proposed Invenergy units would be placed in service in either 2017 or 2018. Our modeling also included Geronimo Energy's proposal for distributed solar generation, with an aggregate capacity of up to 100 MW, to be placed in service by the end of 2016 to take advantage of the federal Investment Tax Credit. And our modeling included Great River Energy's proposal for a three-year purchase of either 100 MW or 200 MW of resource capacity credits only, no energy or generation would be associated with the purchase.

The peaking resources were modeled as dispatchable units with heat rate curves that reflect the units' efficiency at various generation levels. Each unit's maximum capacity was modeled as approximately 230 MW in the winter and 215 MW in the summer. The fuel costs were based on the forecasted costs of natural gas at the Ventura hub, with transportation cost adders included to reflect the expected cost at each of the sites. A scenario to reflect a large natural gas, combined-cycle unit was also run through the Strategist model. Natural gas, combined -cycle generators have higher capital expenditures for construction, but are more fuel efficient when generating.

Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

A. Based on our Strategist modeling, the Company determined Black Dog Unit 6 was the most cost-effective resource on a Present Value Societal Cost (PVSC) basis, as required under Minnesota regulations, as evidenced by the fact that it was included in each of the top 20 resource plans identified in the Company's analysis. The most effective portfolios identified by Strategist consisted of Black Dog Unit 6 being deployed in conjunction with either the Calpine Project or the Invenergy Cannon Falls project, on a PVSC basis. Our modeling did not conclude that the Geronimo Solar Project was a least-cost resource.

Q. DID THE COMPANY ANALYZE THESE RESOURCES ON A PRESENT VALUE REVENUE REQUIREMENTS BASIS?

Yes, we used the Strategist resource planning model again to evaluate our resource selection consistent with the requirements of this Commission. We used the same assumptions and forecast information as we did in the Minnesota CAP proceeding but expressed our modeling results as a Present Value of Revenue Requirements (PVRR) comparison, consistent with North Dakota law. Table 4 provides the results of this analysis.

Table 4
PVSC v. PVRR of Portfolios ($millions)

Resource Combination	2013-2050 PVSC ($millions)	2013-2050 PVRR with ND Assumptions ($millions)
Calpine PPA + Black Dog 6	$45,368	$39,180
Black Dog 6 + RRV 1&2	$45,404	$39,198
Cost/(Savings) of Calpine PPA + Black Dog 6	($36)	($18)

Our cost analysis shows that the acquisition of the 485 MW combination of Black Dog Unit 6 (207 MW accredited capacity) and Calpine Project PPA (278 MW accredited capacity) is less expensive on both a PVRR and PVSC basis than the 621 MW combination of Black Dog Unit 6 and the two Red River Valley Units (207 MW accredited capacity each).

Q. DOES THE ADDITIONAL $18 MILLION COST ASSOCIATED WITH THE EXTRA 136 MW OF THE BLACK DOG AND RED RIVER VALLEY CTS PRESENT MORE VALUE THAN THE COMBINATION OF BLACK DOG UNIT 6 WITH THE CALPINE PROJECT PPA?

A. I do not believe it does. As I discuss in more detail below, the addition of 278 MW of combined cycle capacity to our system through the Calpine Project PPA provides the Company significant operational flexibility as it faces the loss of intermediate and baseload capacity over the next decade as a result of retiring generation units and expiring PPAs.

Q. DID THE COMPANY DO OTHER ANALYSES OF THE COST-EFFECTIVENESS OF THE CALPINE PROJECT PPA?

A. Yes. While the above analyses show that the Calpine Project PPA is a reasonable and prudent decision based on the alternatives available to us through the CAP docket, we also believe it is appropriate to present the most recent vintage information on the cost effectiveness of the Calpine Project PPA so that the benefits and the burdens of acquiring this resource can be appropriately evaluated by the Commission. To do this, we used the 2014 load forecast and resource availability assumptions included in our 2015 Resource Plan recently filed with the Commission, which is our most recent load forecast update.

Q. PLEASE DESCRIBE THIS ADDITIONAL ANALYSIS THE COMPANY CONDUCTED ON THE CALPINE PROJECT PPA.

A. As the Commission knows, Strategist simulates the operation of the NSP System and estimates the total cost of energy over the life of the project on a present value basis. We also use the model to test results under a range of input assumptions. To assess the impact on customer costs, we simulated the operation of the NSP System with and without the addition of the Calpine Project PPA. For purposes of this analysis we considered the PPA in isolation rather in combination with the other proposed new generators.

MISO generally dispatches combined cycle intermediate load units on an economic basis during peak to support and balance baseload units and intermittent resources. The energy produced by an economically dispatched CC unit generally displaces a similar amount of more expensive energy that would have been produced by the Company or otherwise purchased elsewhere. The Strategist analysis identifies a displacement of approximately 18,300,000 MWh of more expensive generation, which accounts for the differences in the cost of system operations with and without the Calpine Project PPA.

We also conducted various "sensitivity tests" to evaluate how the Calpine Project PPA will affect system costs under different circumstances. The sensitivities analyzed include the effect on system costs if one assumes (1) the Fall 2011 Forecast of capacity need relied upon by the MPUC (i.e., a need of 150-500 MWs in the 2017-2019 timeframe), (2) no MISO market purchases available to supplement system resources (Markets Off), and (3) higher and lower gas costs.

As Table 5 below shows, our analysis estimates that the overall system cost of energy with the Calpine Project PPA added to our system (on a PVRR basis without considering any costs associated with CO2 emissions or externalities) is $11 million lower than it would be without the this resource being on our system.

Table 5:
Total System Cost With/Without Calpine Project PPA

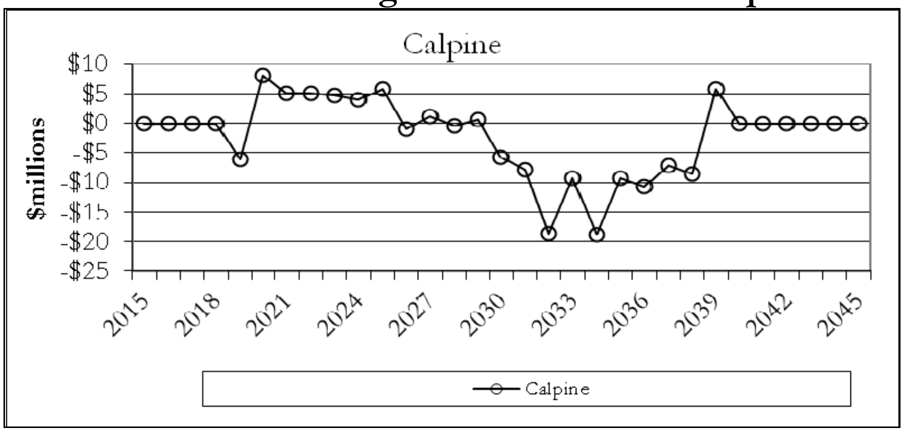
Changes in PVRR Cost ($millions)	Base Case Using ND Assumptions	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case Using ND Assumptions	$44,949	**$49,279**	$41,260	$50,050	$45,957	$51,971
Base Case Using ND Assumptions with Calpine Project PPA	$44,937	**$49,257**	41,271	$50,010	$45,883	$51,944
Net Cost/(Savings)	($11)	**($22)**	$10	($40)	($74)	($27)

Our analysis also concluded that the addition of the Calpine Project PPA reduces system costs for all sensitivities except when the price of gas is low, as shown in the above table.

Q. HOW ARE THE CALPINE PROJECT PPA COSTS SPREAD OVER TIME?

A. Figure 4 below illustrates the year-over-year annual net costs or savings of the Calpine Project PPA during its 20-year life, which results in the net $11 million savings identified in the table above. Except for 2019, the cost of energy over the first 10 years of the PPA does not offset its capacity cost, while energy savings in the second 10 years of the PPA more than offset its capacity cost to achieve the overall net savings of $11 million over the PPA's 20-year term.

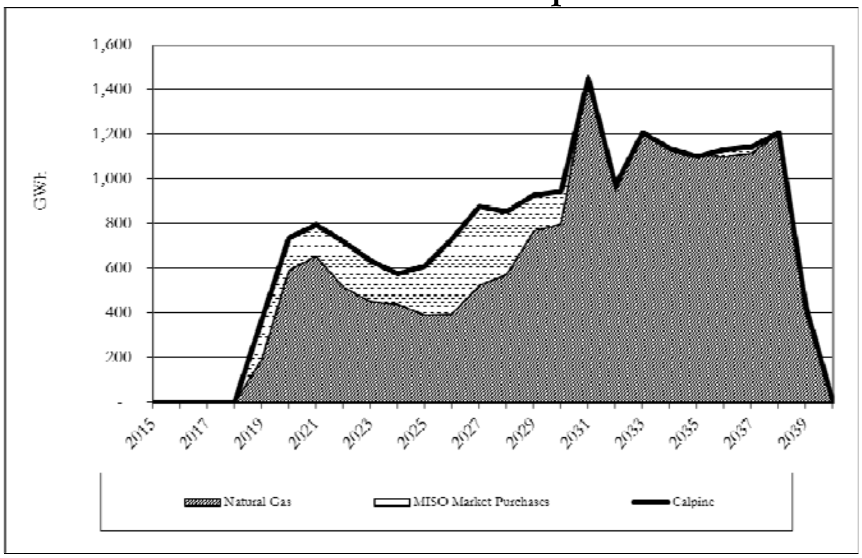
Figure 4:
Annual Net System Costs (Savings) with Calpine Project PPA Compared to Base Case Using North Dakota Assumptions



Q. WHAT IS THE PROFILE OF THE 18,300,000 MWH OF MORE EXPENSIVE GENERATION THAT THE CALPINE PROJECT PPA DISPLACES?

A. Figure 5 below illustrates the results of the Strategist dispatch simulations for the Base Case using North Dakota assumptions (i.e., a "Markets On" scenario with no additional renewable generation selected by Strategist and no externalities or carbon cost). In this scenario Strategist may choose to purchase market energy to meet system needs. Over the 20-year term of the PPA, approximately 87 percent of the Calpine Project PPA's generation displaces other natural gas generation, and 13 percent displaces market energy.

Figure 5:
Calpine Project PPA – Displaced Energy for Base Case Using North Dakota Assumptions



Q. WHAT IMPACTS WILL THE CALPINE PROJECT PPA HAVE ON CUSTOMER RATES?

A. While the Calpine Project PPA represents the addition of a combined cycle unit to our system, the customer rate impacts will be mitigated when spread across the entire NSP System because the System is so large. As shown in Table 6 below, our Strategist dispatch simulation forecasts for most years show the rate impact of the Calpine Project PPA (energy and capacity costs) to be significantly offset by avoiding higher priced fossil fuel energy and market energy purchases.

**Table 6:
Calpine Project PPA Impacts
(¢/kWh)**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000	0.000	0.000	0.000¢	0.041	0.070	0.071	0.072	0.073 0	0.073 0	0.074
Fuel Clause	0.000	0.000	0.000	0.000	0.036	0.077	0.088	0.080	0.073	0.069	0.074
Avoided Fuel/Mkt Purchases	0.000	0.000	0.000	0.000	-0.091	-0.129	-0.148	-0.140	-0.134	-0.133	-0.135

As shown in Table 7 below, the initial net rate impact of the Calpine Project PPA is estimated to be 0.014¢ per kWh in 2019, rising to 0.019¢ per kWh in 2020, and then dropping and staying at or below 0.012¢ per kWh through 2024 before rising back up to 0.014¢ per kWh again in 2025.

**Table 7:
Calpine Project PPA Net Rate Impacts (10 Years)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0.000¢/ kWh	0.000¢/ kWh	0.000¢/ kWh	0.014¢/ kWh	0.019¢/ kWh	0.012¢/ kWh	0.012¢/ kWh	0.011¢/ kWh	0.009¢/ kWh	0.014¢/ kWh

Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE CALPINE PROJECT PPA?

A. Yes. The Calpine Project PPA provides value in light of a reduction in baseload and intermediate resources on our system in the next decade due to unit retirements and expiring PPAs. The PPA also provides value with respect to controlling the risk of emerging environmental regulations.

Q. PLEASE DESCRIBE THE VALUE OF THE CALPINE PROJECT PPA WITH RESPECT TO THE REDUCTION OF BASELOAD AND INTERMEDIATE CAPACITY RESOURCES

ON THE COMPANY'S SYSTEM.

A. From 2015-2030, the NSP System will experience significant reductions in energy resources due to power contracts expiring without extension or renewal. Several potential key changes include the following:

- 2023- Blue Lake Units 1-4 cease operation (153 MW)
- 2025- Manitoba Hydro contracts expire (850 MW)
- 2026- Cottage Grove combined cycle contract expires (262 MW)
- 2027- Mankato combined cycle contract expires (357 MW)

Further, in the 2030-2035 timeframe, the Company faces the potential retirement of three baseload nuclear units, along with Sherco Units 1 and 2 retiring after a 60 year operating life. Altogether this suggests that a significant proportion of our baseload generation may be retired within 15 to 20 years. These five generating units have been the backbone of the NSP System for many years and have formed the foundation to provide low cost and highly reliable service to our customers.

With respect to Sherco, there is the possibility that Unit 1 may be retired as early as 2025, and we have included modeling in our 2015 Resource Plan to identify system requirements in the case that occurs. The addition of the Calpine PPA is a hedge against that possibility. Current technology suggests that natural gas combined cycle units, along with additional renewable energy, will be the likely candidates to replace the energy and capacity these units have provided. As a result of the large potential exposure to add natural gas to our system in the 2025 to 2035 timeframe, the Company must attempt to minimize this exposure going into that timeframe. The addition of the Calpine PPA in 2019 minimizes the Company's exposure to this risk, allowing for greater flexibility to respond when our backbone baseload plants are retired.

Q. PLEASE EXPLAIN HOW THE CALPINE PROJECT PPA MINIMIZES THE RISK ASSOCIATED WITH THE DECLINE IN BASELOAD CAPACITY.

A. First, the Calpine PPA locks in very competitive pricing for natural gas combined cycle generation for the next twenty years. Second, this competitively priced capacity resource is capable of intermediate and baseload operation, offering a flexible option to conservatively address the uncertainty of our forecasted capacity need. In addition, the Calpine Project PPA is capable of significant energy production that enhances system flexibility for a variety of system outcomes.

Q. HOW DOES THE CALPINE PROJECT PPA MINIMIZE THE RISK ASSOCIATED WITH EMERGING ENVIRONMENTAL REGULATIONS?

A. Despite our strategy of shifting our resource portfolio toward lower-emission options while maintaining our focus on fuel diversity, affordability and reliability, we continue to experience significant uncertainty surrounding environmental regulation. Probably the biggest – and most uncertain – factor is the EPA's existing source GHG performance standard, known as the Clean Power Plan or Section 111(d) Rules, which EPA expects to finalize in mid-summer 2015. The final rule is likely to face legal challenges, which depending whether or not the rule is stayed during litigation, may affect the timeline for state plan development. If the Rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later; compliance will begin in 2020.

While much remains unknown, it seems clear that the Rule will (1) put increasing pressure on coal plants, possibly resulting in reduced utilization levels or additional retirements; (2) likely increase generation from existing and new natural gas plants; and (3) push us to continue adding renewable energy resources and increasing energy efficiency efforts and associated investments. The addition of the Calpine PPA hedges against these likely outcomes. It constitutes intermediate capacity that can step in to support the NSP System due to impacts the any future environmental regulation may have on our key generating facilities, including our baseload coal units at the Sherburne County Generating Station and our Allen S. King Plant.

V. PRUDENCE OF PROPOSED RESOURCE PORTFOLIO (BLACK DOG, CALPINE, AND GERONIMO)

Q. DID THE COMPANY ANALYZE THE COSTS AND BENEFITS OF THE ENTIRE RESOURCE PORTFOLIO IT IS PROPOSING?

A. Yes. To provide context for the Commission's evaluation of this ADP request, we conducted modeling that identifies the costs of various combinations of the three resources we propose to acquire: Black Dog Unit 6, the Calpine Project PPA, and the Geronimo Solar PPA. Tables 8 and 9 below present the PVRR results of the specified combinations of resources, and the results of the same sensitivity tests that we conducted for the Calpine Project PPA.

Table 8:
PVRR Results ($millions)

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Base case using ND Assumptions	$44,949	$49,279	$41,260	$50,050	$45,957	$51,971
Add Geronimo Solar PPA	$45,011	$49,350	$41,336	$50,094	$46,006	$52,005
Add Calpine Mankato CC PPA	$44,937	$49,257	$41,271	$50,010	$45,883	$51,944
Add Black Dog 6	$44,836	$49,162	$41,159	$49,923	$45,825	$51,868
Add Geronimo & Calpine	$45,012	$49,328	$41,358	$50,070	$45,947	$51,992
Add Calpine & BD6	$44,842	$49,155	$41,186	$49,902	$45,767	$51,849
Add Geronimo & Calpine & Black Dog 6	$44,929	$49,219	$41,286	$49,974	$45,842	$51,908

Table 9:
Incremental PVRR from Base Case ($millions)

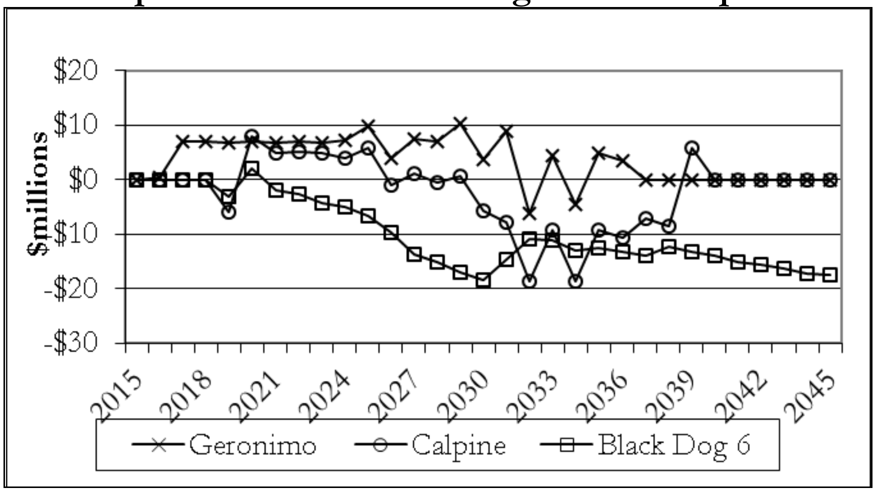
Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base case using ND Assumptions	$0	$0	$0	$0	$0	$0
Add Geronimo Solar PPA	$62	$71	$76	$44	$49	$35
Add Calpine Mankato CC PPA	($11)	($22)	$10	($40)	($74)	($27)
Add Black Dog 6 CT	($112)	($118)	($101)	($127)	($132)	($103)
Add Geronimo & Calpine	$63	$48	$98	$20	($10)	$21
Add Calpine & Black Dog 6	($107)	($124)	($74)	($147)	($190)	($122)
Add Geronimo & Calpine & Black Dog 6	($20)	($60)	$26	($76)	($115)	($63)

Notably, the addition of the Calpine Project PPA together with Black Dog Unit 6 provides the most Present Value of Revenue Requirements (PVRR) savings of the combinations provided. Further, the Geronimo Solar PPA in combination with the Calpine Project PPA and Black Dog Unit 6 provides a net reduction in the PVRR in all scenarios except the low gas case.

Q. WHAT IS THE AGGREGATE IMPACT OF ADDING THE THREE RESOURCES OVER TIME?

A. Figure 6 below shows the aggregate impact of the Calpine Project PPA, Black Dog Unit 6, and the Geronimo Solar PPA.

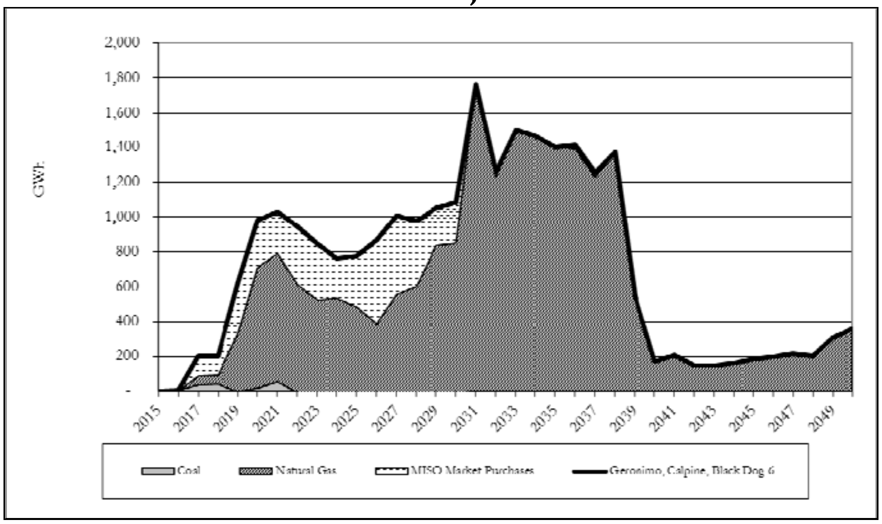
Figure 6:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions



Q. WHAT IS THE PROFILE OF THE MORE EXPENSIVE ENERGY DISPLACED BY THE ADDITION OF BLACK DOG UNIT 6, THE CALPINE PROJECT PPA, AND THE GERONIMO PPA?

A. Figure 7 below illustrates the results of the Strategist dispatch simulations for the Base Case using North Dakota assumptions (i.e., a "Markets On" scenario with no additional renewable generation). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 85 percent of the aggregate generation displaces natural gas-based generation, 16 percent displaces market energy, with coal generation output having a net increase of 1 percent.

**Figure 7:
Strategist Simulations - Displaced Energy Base Case Using ND Assumptions for combination of Geronimo, Calpine, and Black Dog 6 Projects**



As shown, the overall impact of adding all three resources on the operation of the NSP System is displaced natural gas generation.

Q. WHAT IS THE AGGREGATE RATE IMPACT OF ADDING BLACK DOG UNIT 6, THE CALPINE PROJECT PPA, AND THE GERONIMO PPA TO THE SYSTEM?

A. Table 10 below shows the rate impact of the various combinations.

**Table 10:
Annual Rate Impact Analysis**

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh
CALPINE	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh	0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh
BLACK DOG 6	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh	(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)
GERONIMO + CALPINE	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh	0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh
CALPINE + BLACK DOG 6	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh	0.029¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh
GERONIMO + CALPINE + BLACK DOG 6	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh	0.055¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

PUBLIC DOCUMENT -
TRADE SECRET DATA EXCISED

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR A POWER PURCHASE AGREEMENT WITH MANKATO ENERGY CENTER, LLC FOR APPROXIMATELY 345 MW OF COMBINED-CYCLE NATURAL GAS GENERATION

Case No. PU-15-_____

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Paul B. Johnson, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Xcel Energy Services Inc., the service company subsidiary of Xcel Energy, in the above captioned matter, that he has read the testimony and schedules submitted in the above captioned matter under his name, that they were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Paul B. Johnson

Paul B. Johnson

Subscribed and sworn to before me this 12th day of February, 2015.

Notary Public
My Commission Expires: 1-31-2020

CYNTHIA D. HARRINGTON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2020

Paul B. Johnson
Director Resource Planning and Bidding
Northern States Power
411 Nicollet Avenue
Minneapolis, MN 55345
_612-330-5656_
paul.b.johnson@xcelenergy.com

PROFESSIONAL EXPERIENCE

Director Resource Planning and Bidding **July 2014 –Present**

Xcel Energy, Minneapolis, MN

- Develop and direct the systems, processes and personnel required to prepare effective and prudent long term system plans for each of the four Xcel Energy operating utilities.
- Develop and direct the systems, processes and personnel required to conduct effective and fair power solicitation processes to procure needed power and energy to meet native load demand and energy requirements and achieve cost reductions in the Xcel supply portfolios.
- Direct acquisition of up to 800 MW per year of additional capacity and for management of the various state resource planning processes in a manner to fulfill requirements and meet company objectives meeting native load requirements and company asset growth goals.

Manager Power Supply Planning **March 2012—June 2014**

Old Dominion Electric Cooperative (ODEC), Glen Allen, VA, a large G&T Cooperative serving 11 distribution cooperative members located in VA, MD and DE who serve over 1.3 million customers with a peak load of about 3000 MW.

- Directed long term power supply area of ODEC managing all ongoing power supply analysis, requests for proposals, PPA negotiations for renewable and thermal resources and planning analysis and issue or hot topic updates responsive to ODEC Board requests which meets monthly.
- Directed selection, implementation and ongoing management and updates of all planning models and data sources used for long term planning.
- Worked effectively and collaboratively with all areas of ODEC to successfully fulfill corporate and business unit objectives for current budget year.
- Actively develop staff providing growth opportunities within power supply planning and with other areas of ODEC.
- Kept abreast of developments and trends in PJM and electric industry and evaluate potential impact as a part of long term planning efforts and updates to executive management and Board members.

President, S&P Energy, LLC **October 2011--February 2012**

I formed S&P Energy LLC October 2011in response to interest by others in my network to work with other consulting firms and development companies with all aspects of renewable project development and marketing (permitting, interconnection, off-take prospects and contracting, RFP responses, etc.).

- Worked as contract consultant with Bridge Energy Group as key resource for interconnection report development and filing support for large Californian utility to the California ISO involving over 120 reports (November 2011through January 2012)
- Pursued consulting contract negotiations for work with a couple renewable project developers and biomass fuel production facility developers.

Sr. Manager, Development North central and Eastern Regions **April 2009—May 2011**

RES Americas, Minneapolis, MN, a national wind and solar project development and construction company. I have management responsibility of regional office in Minneapolis under Regional Vice

President Minneapolis Office has active project pipeline of nearly 2000 MW.

- Direct project management responsibility for development and power marketing of 300 MW Wind Project in southeastern, MN Successfully initiated and navigated permitting to advanced stage resulting in MPUC unanimous October 2010 approval of site permit and certificate of need. Led effort to successfully gain unanimous Mower County Commissioner approval of permits for two transmission routes and three substation sites. Provided direction and support for project interconnection options and study evaluation and effective and timely interaction with Midwest Independent System Operator (MISO) staff.
- As member of company-wide management team participated in 2010 effort to evaluate and refine RES Americas business strategy and identify key implementation efforts.
- Established and maintained project marketing relationships and RFP follow-up with electric utilities in MN, WI, IA, OH and TN.
- Actively monitored renewable market project development and sale opportunities which resulted in relationships with new power purchase prospects in upper Midwest and Eastern US.
- Led effort to evaluate potential biomass fuel opportunity and led effort to develop a biomass fuel business plan for generation market in US and Europe. This effort relied on extensive biomass fuel and biomass power market research.
- Identified and completed initial due diligence for potential acquisition of biomass fuel planting, harvesting and combustion technologies for utility-scale greenfield and retrofit biomass power generation projects.
- Completed preliminary work on strategic approach for wind project development in eastern US based on current and projected changes in renewable market and electric utility generation plans.

Several key positions with Minnesota Power, Duluth, MN June 1999—April 2009

An 1800 MW investor-owned electric utility serving 140,000 customers.

Renewable Energy Project Development Manager October 2006—April 2009

- Developed and led turbine 2008 purchase solicitation, screening and contract negotiation process which resulted in executed contract for 33 turbine project in North Dakota.
- Developed and gained management support for capital budget and project development plan for several 100 MW of wind generation development. Supported executive management's effort to secure budget and initial project approval.
- Initiated and continued to direct multi-year wind prospecting effort which resulted in met tower siting and installation on several project site in northeastern Minnesota. Prospecting effort also identified large area with high average winds within economic distance of grid interconnection. Oversaw successful wind option acquisition effort with sufficient land and wind rights to support substantial wind project development.
- Provided site control and project information necessary to maintain interconnection study process and avoid higher study costs.
- Developed and directed 2004 and 2007 All Source Request for Proposals through bid completeness, evaluation, short-list, contract negotiation and filing with state public utilities commission (all filed contracts approved).
- Successfully led negotiation team for four wind-based power purchase agreements totally 156 MW.
- Developed, maintains and directs implementation of renewable strategy responsive to corporate strategy and direction of key state and federal policies.
- Developed and managed relationships with major wind developers, turbine suppliers and regulators essential for continuing to increase wind portion of Minnesota Power renewable power supply.
- Managed hand-off to project construction team of permitted, sited projects with turbines.
- Provided liaison as needed with MP executive management, outside consultants and key landowners to resolve issues and keep wind generation project progress on schedule.

Strategic Initiatives—Project Leader **September 2002—October 2006**

- Directed development and implementation of long term power supply request for proposals for renewable, bridge transactions and long tern purchases; evaluation and PPA negotiation completion by mid-2005.
- Led multi-area effort to develop and maintain MP's long term plan and develop and defend MP's biennial 15-year Resource Plan filed in September 2004.
- Developed long term power sales responses to RFPs and manage post-bid submittal follow-up through buyer screening and short-list announcement
- Identified long term power market and generation technology developments, trends, events and provide assessment executive management.
- Led and manage multi-area generation strategy development to support executive management decisions.
- Managed long term generation asset sale process including buyer due diligence and definitive agreement development.
- Tracked and provided assessments of regional generation development and performance of existing regional generation.

Generation Development –Project Leader **June 1999—August 2002**

- Managed internal generation development agreement compliance.
- Identified and screened generation development opportunities as key member of generation development team and lead project due diligence under executive management direction.
- Led effort to deploy and integrate price forecasting and generation opportunity evaluation tools into management decision processes.
- Monitored electric industry and key data sources for competitive intelligence and use this information to improve timing and focus of generation development.

ELECTRIC UTILITY INDUSTRY COMMITTEE LEADERSHIP OPPORTUNITIES

- Edison Electric Institute Renewables Committee. Committee developed policy proposals on federal renewable policy initiatives to reflect position of member investor-owned utilities)
- EPRI Storage and Renewables Task Force (Biomass/Waste Fuel Working Group Chair) Efforts resulted in gaining $85 million DOE funding commitment to complete engineering and build first 100 MW biomass power using "whole tree energy" technology. Also chaired national biomass technology symposium jointly hosted by EPRI and DOE in Washington, DC.

EDUCATION

Bachelor of Science and **Master of Arts** Environmental Studies
Bemidji State University. Bemidji, MN

Completed extensive graduate studies in organic chemistry, ecology, macro/micro economics, environmental law, politics of pollution and many special topic research papers requiring peer defense. Degree was designed to prepare students to understand industrial environmental issues and regulatory requirements, pollution control and renewable technologies, law and associated environmental impacts. Served as graduate assistant in library and physics lab. Completed graduate internship with regional development commission providing technical support to environmental projects.