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
Aurora Distributed Solar, LLC for Up to 100 MW of Solar Generation

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

Resource Need and Geronimo Solar PPA Testimony

February 13, 2015

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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 Aurora Solar, LLC, an affiliate of Geronimo Energy, LLC (Geronimo Solar PPA), including the factors and analysis that went into determining the resource need. I also discuss the terms of the Geronimo Solar 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 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 led to 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 Geronimo Solar 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?

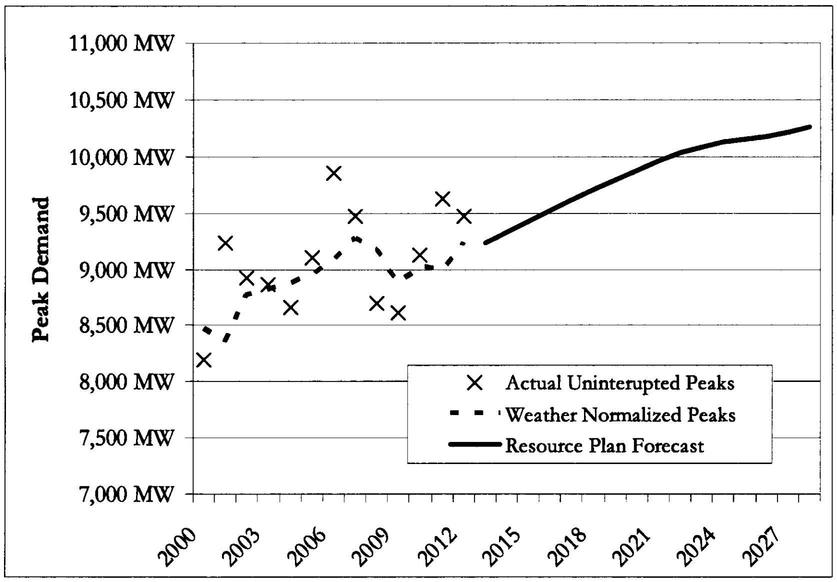
A. The Company's need is 150-500 MW by 2019/2020, based on our updated Fall 2011 forecast (Fall 2011 Forecast). This forecast updated the initial forecasting included in our 2010 Resource Plan. Augmented with information from the Company's Spring 2013 forecast, the Fall 2011 Forecast is the forecast 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 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

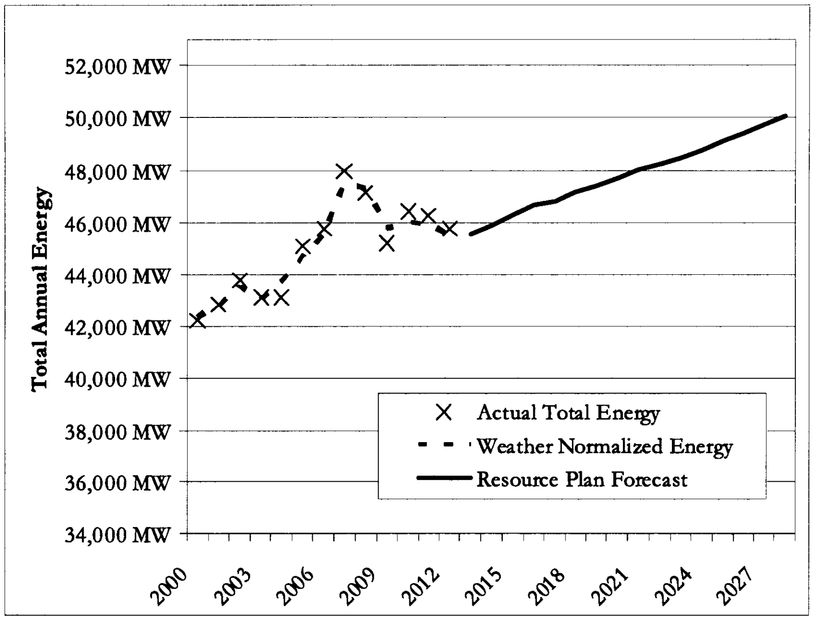
1, from 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

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 ten 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. GERONIMO SOLAR PPA

Q. PLEASE DESCRIBE THE GERONIMO SOLAR PPA?

A. The 20-year Geronimo Solar PPA will provide up to 100 MW of nameplate capacity from distributed solar facilities located at up to 24 sites in Minnesota, and ranging in size from 2 to 10 MW. Each solar facility will interconnect to the Company's distribution substations, utilizing excess available transfer capability to inject power into the system at distribution voltage.

The PPA is based upon the Company's Model Solar PPA, which has been used in several jurisdictions to procure solar energy. This allowed the Company to utilize standardized terms and conditions that it has used with other solar generation, resulting in enhanced certainty and consistency with other Company contracts.

Q. WHAT ARE THE PRINCIPAL TERMS OF THE GERONIMO SOLAR PPA?

A. The Geronimo Solar PPA has a single bundled per MWh capacity/energy price structure. This means that all payments to Geronimo are on a per-MWh basis, with no separate payment for capacity. Geronimo is contractually committed to obtain approximately 71 percent capacity accreditation for the total nameplate capacity it achieves under the PPA. This means that if the nameplate capacity of the project is 100 MW, the Company will obtain about 71 MW of accredited capacity pursuant to the MISO accreditation process. The PPA contains a mechanism to compensate the Company if the capacity level is less than Geronimo has committed to in the PPA.

To accommodate tax equity financing, the parties negotiated a single PPA structure covering all of the solar facility 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 with respect to 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. This structure also provides Geronimo the flexibility to reduce the aggregate size of the nameplate capacity of the PPA if circumstances warrant. The maximum nameplate capacity that may be delivered under the PPA is capped at 100 MW.

Geronimo is also entitled to a 30 percent investment tax credit (ITC) for all project phases that achieve commercial operation by the end of 2016. The 30 percent ITC will automatically reduce to 10 percent absent Congressional action for projects going into service beginning in 2017. This means that development and construction decisions are time-sensitive for Geronimo to ensure that all the phases covered by the PPA will timely qualify for the available ITC at the end of 2016.

Q. PLEASE DESCRIBE THE RISKS OF THE PPA.

A. The Geronimo Solar PPA had risks with respect to (1) potential delay; (2) transmission interconnection; (3) total capacity and capacity accreditation; (4) curtailment costs; (5) environmental costs; (6) financial security; (7) construction and operational issues; and (8) the phase-in approach to the distributed facility sites.

Q. PLEASE DESCRIBE HOW THE DELAY RISK HAS BEEN MITIGATED?

A. Geronimo's pricing depends in part on its phases qualifying for the ITC. There is no mechanism to increase the price if phases go into service after expiration or reduction of the ITC (currently scheduled to reduce from 30 to 10 percent at the end of 2016). However, the PPA allows Geronimo to stop development of phases and effectively reduce the size of the project if they are unable to complete them in time to qualify for the ITC.

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

A. None of the Project's phases require interconnection to the transmission grid; they are all connected to the Company's system at the distribution level. Geronimo bears all distribution interconnection costs.

Q. WHAT ARE THE CAPACITY AND CAPACITY ACCREDITATION RISKS AND HOW HAVE THEY BEEN MITIGATED?

A. The PPA can deliver up to 100 MW of nameplate capacity. To incentivize Geronimo to deliver the highest possible capacity up to that cap, the PPA includes a scale of damage payments that escalates the further the aggregate MW level of the PPA falls short of the 100 MW cap. In addition, failure to obtain 71 percent accreditation of the actual nameplate capacity delivered under the PPA results in damages for the period of the accredited capacity shortfall.

Q. PLEASE DESCRIBE THE COMPANY'S MITIGATION OF THE CURTAILMENT RISK.

A. The PPA provides a mechanism to determine whether and under what circumstances the facility's output is curtailed. These provisions are similar to those typically included in our wind and other solar PPAs, modified only to account for technical differences related to the PPA's distributed solar facility sites. Curtailments arising out of the operation of the system are generally not compensable, while curtailments arising for economic reasons generally are compensable. This is because economic curtailments will be initiated when it is more economic for the Company to curtail the resource (due to negative LMPs, for example) than to let the resource continue to generate (at negative prices). Economic curtailment limits the total cost paid by customers. Unlike wind, solar is an "on-peak" resource and will likely experience fewer curtailments due to negative LMPs or system balancing issues. This is true for both distribution and transmission interconnected resources.

Q. HOW DOES THE PPA MITIGATE THE RISK OF ENVIRONMENTAL COSTS?

A. Under the PPA, the Company will own the environmental and renewable energy credits.

Q. WHAT IS THE MITIGATION OF THE FINANCIAL RISK OF THE PPA?

A. 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 Solar PPA. In addition, Geronimo takes all ITC qualification risks.

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

A. 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.

Q. HOW HAVE THE RISKS ASSOCIATED WITH THE PHASE-IN APPROACH TO THE DISTRIBUTED SOLAR FACILITY SITES BEEN MITIGATED?

A. As I previously explained, the PPA has been negotiated to provide flexibility both as to the timing of completing phases and the aggregate capacity of all completed phases. In order to stage construction and to maximize the potential for project phases to qualify for the ITC, we anticipate that some number of phases may be completed before September 1, 2016, when the PPA authorizes the project to commence commercial operation at the contract price. The PPA provides that the Company will take pre-COD energy produced by a phase before that date. However, the pricing for this pre-COD energy is based on the prevailing market rate. Conversely, as mentioned before, if circumstances warrant, the developer can reduce the aggregate nameplate capacity of the PPA by eliminating phases and making the agreed-upon capacity buy-down payment to the Company.

Q. WHAT IS THE MITIGATION FOR 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. There are two primary conditions that Geronimo must meet to perform under the PPA: (1) a master site permit for all the facility sites in the aggregate or individual site permits for each phase; and (2) satisfactory arrangements for the interconnection of the project phases.

The Company has one important condition precedent. Within ten days after receipt of an order of the MPUC approving the PPA, The Company must request approval of the PPA from this Commission. The MPUC Order approving the Geronimo Solar PPA was issued February 5, 2015. The present filing was made on February 13, 2015, within the ten day window.

The Company's obligation under the PPA is to seek an order from the Commission that affirmatively states the Company's execution of the PPA is reasonable, in the public interest, and that all costs incurred under the PPA are recoverable from our customers subject to ongoing prudency review of Company's performance and administration of the PPA. The Company retains the right to terminate the PPA if the Commission does not approve the PPA, or denies the Company recovery of the costs incurred under the PPA as currently allocated to North Dakota customers by ratemaking mechanisms currently in effect.

IV. PRUDENCE OF GERONIMO SOLAR PPA

Q. WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING THE PRUDENCE OF THE GERONIMO SOLAR PPA?

A. The two principal factors are (1) whether the Geronimo Solar PPA is appropriate to meet the Company's identified need, and if so, (2) does it effectively meet the need at a reasonable cost. Mr. Haeger addresses how the addition of the up to 71 MW of capacity from the Geronimo Solar PPA meets our need, and I address how the PPA meets that need at a reasonable cost.

Q. HOW DID THE COMPANY ANALYZE THE WHETHER THE GERONIMO SOLAR PPA MEETS THE COMPANY'S NEED AT A REASONABLE COST?

A. The Company used the Strategist resource planning model to evaluate the costs of the up-to-100 MW Geronimo Solar PPA. 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 used 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 Geronimo Solar PPA. For purposes of this analysis we considered the PPA in isolation and not in combination with the other proposed new generators.

MISO generally dispatches solar production ahead of other generation such as gas and coal-based generation. Consequently, the more solar energy produced, the less fossil generation is operated. And when the energy from solar resources is produced, it displaces a similar amount of energy that would either have been produced by the Company or purchased elsewhere. The Strategist analysis identifies a displacement of approximately 200,000 MWh of fossil generation, which accounts for the differences in the cost of system operation with and without the Geronimo Solar PPA.

We also conducted various "sensitivity tests" to evaluate how the Geronimo Solar 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 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. Table 4 below provides the results of these analyses.

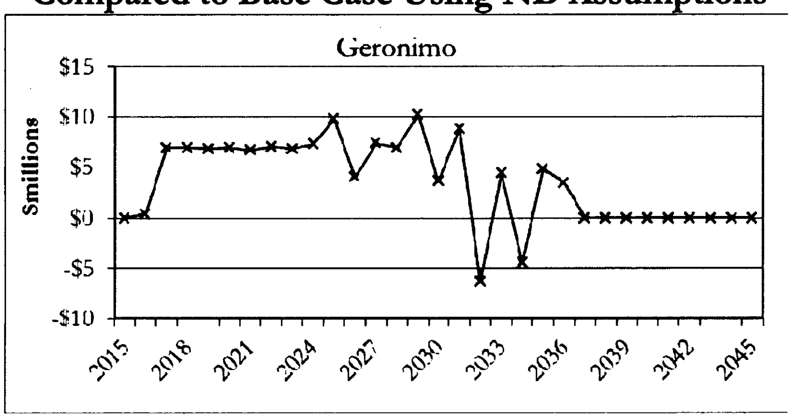
Table 4:
Net PVRR Cost/Savings of Geronimo PPA for Key Sensitivities

Sensitivities =>	Base	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Geronimo PPA vs Base Case with ND Assumptions	$62	$71	$76	$44	$49	$35

Q. HOW ARE THE GERONIMO SOLAR PPA COSTS SPREAD OVER TIME?

A. Figure 4 below illustrates annual net costs or savings over the 20-year life of the PPA for the Geronimo Solar Project that lead to the $62 million PVRR impact. As shown over the term, the Geronimo Solar Project moves from net cost to net savings on an annual basis in the out years due to the displacement of thermal energy resources.

Figure 4:
Annual Net Costs (Savings)
Compared to Base Case Using ND Assumptions



Q. WHAT IS THE PROFILE OF THE MORE EXPENSIVE GENERATION THAT THE CALPINE PROJECT PPA DISPLACES?

A. Figure 5 below illustrates the results of the Strategist dispatch simulations using the Base Case under North Dakota assumptions (i.e., a "Markets On" scenario with no additional renewable generation and no externalities or carbon cost). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 60 percent of the solar generation displaces natural gas-based generation, 10 percent displaces coal, and 30 percent displaces market energy.

Figure 5:
Strategist Simulations – Displaced Energy
Base Case Using ND Assumptions

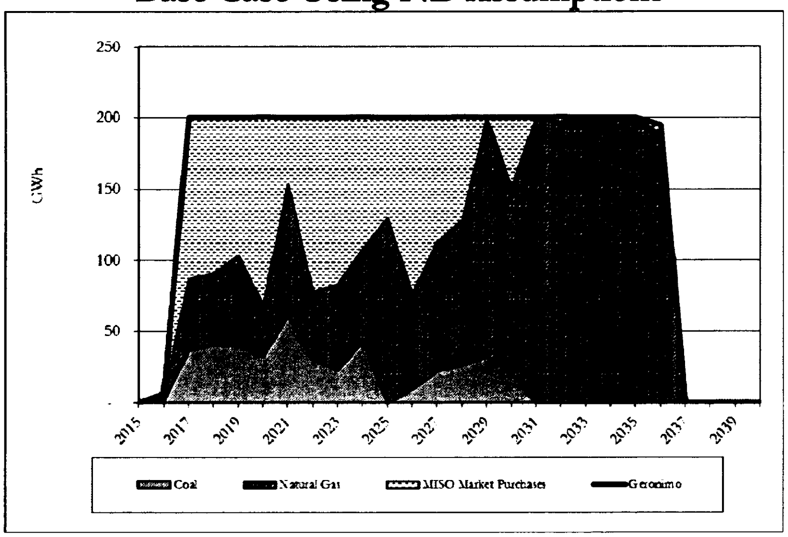
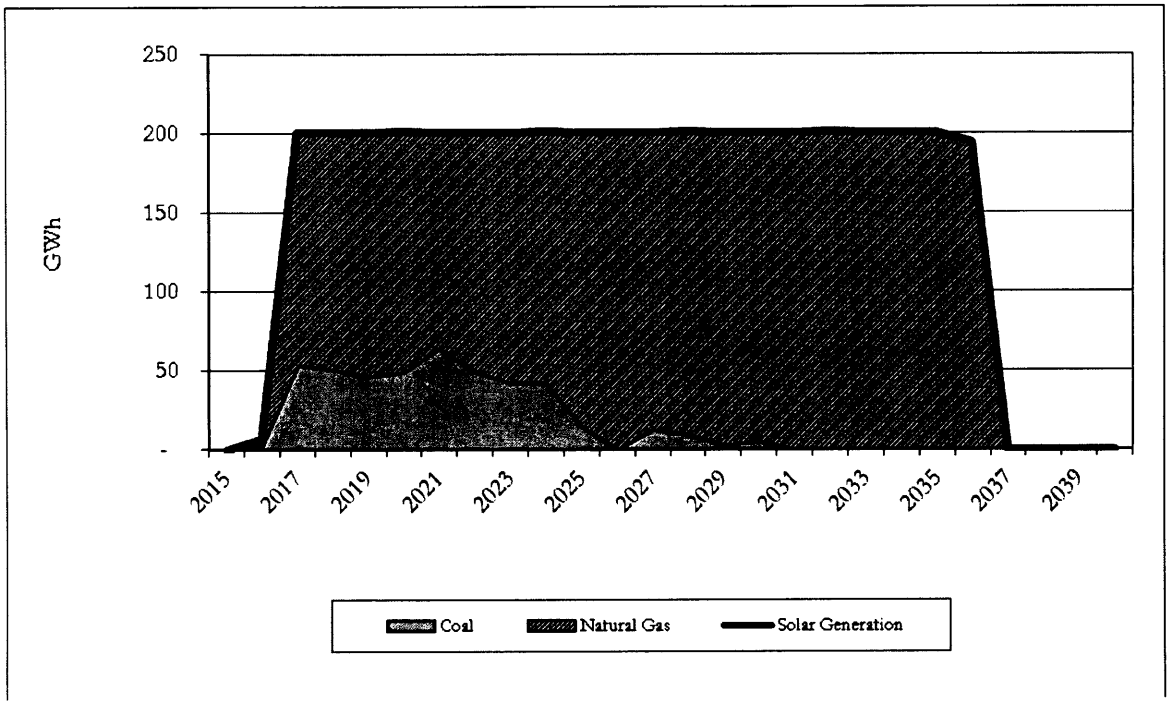


Figure 6 below illustrates the results of the Strategist dispatch simulations under the Markets Off scenario, when just the NSP System is analyzed and only the Company's native generation is displaced by the Geronimo Solar Project. In this scenario, the majority of the solar generation (approximately 89 percent) displaces natural gas-based generation, with the remaining 11 percent is expected to displace coal generation.

Figure 6:
Strategist Simulations – Displaced Energy
Markets Off



To further illustrate the magnitude of the displacement of fossil fuel generation, we analyzed the impact of the Geronimo Solar PPA on our use of natural gas and energy market purchases to meet our customers' demand. Table 5 below shows the levels of natural gas consumption and market purchases for the Base Case using North Dakota assumptions (i.e. the NSP System without the Geronimo Solar Project), and the reduction that would occur in those levels due to the addition of the Geronimo Solar PPA to the system. As shown in the table, the Geronimo Solar PPA is projected to displace 20 Bcf of natural gas and offset over 1.1 million MWhs of market purchases during its 20-year term. This provides the Company a hedge against increases in the costs of natural gas and market energy.

Table 5:
Hedge Value

Total System 2017-2036	Natural Gas *bcf*	Market Purchases *GWh*
Base Case Using ND Assumptions	1,466	104,074
Geronimo	(20)	(1,138)

Q. WHAT IMPACTS WILL THE GERONIMO SOLAR PPA HAVE ON CUSTOMER RATES?

A. While the Geronimo Solar Project represents a large utility scale solar energy acquisition, we estimate that the customer rate impacts will be mitigated when spread across the entire system, because the NSP System is so large in comparison. As shown in Table 6 below, our Strategist dispatch simulation forecasts that for most years the rate impact of the Geronimo Solar Project will be nearly offset by decreases in the cost of fossil fuel and other purchased energy.

Table 6:
Geronimo Solar PPA Impacts
(¢/kWh)

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh
Fuel Clause	0.000¢/kWh	0.001¢/kWh	0.045¢/kWh	0.045¢/kWh	0.046¢/kWh	0.048¢/kWh	0.049¢/kWh	0.050¢/kWh	0.051¢/kWh	0.052¢/kWh	0.053¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	0.000¢/kWh	-0.028¢/kWh	-0.029¢/kWh	-0.030¢/kWh	-0.031¢/kWh	-0.033¢/kWh	-0.033¢/kWh	-0.035¢/kWh	-0.035¢/kWh	-0.030¢/kWh

Table 7 below estimates how average rates will be affected by the Geronimo Solar PPA. The initial rate impact in 2017 is expected to be approximately 0.016¢ per kWh, or about 12¢ per month for a customer using 750 kWh, and stay relatively flat at that level through 2024. The net rate impact will increase somewhat in 2025 when the benefit of avoided fuel and purchased power decreases due to a shift in our mix of system resources and fixed PPA prices approaching the level of anticipated market energy prices.

Table 7:
Geronimo Solar Net Rate Impacts (10 Years)

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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

Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE GERONIMO SOLAR PPA?

A. Yes. We identified two qualitative benefits of the Geronimo Solar PPA in addition to the quantifiable benefits identified above: (1) an environmental hedge benefit; and (2) the ITC qualification benefit.

Q. PLEASE DESCRIBE THE GERONIMO SOLAR PPA'S ENVIRONMENTAL HEDGE BENEFIT.

A. Solar generation provides an emissions-free energy source that can work well in combination with other capacity resources, such as natural gas facilities. Increasing carbon-free generation will further our goals of early compliance with new and emerging emissions requirements and targets.

As noted in our 2015 Resource Plan, this includes pending environmental regulation such as NOx regulations that may impact the continued use of our Sherco Units 1 and 2, as well as EPA's proposed Clean Power Plan. As part of that plan, the Company is proposing to add approximately 2,400 MW of utility-scale and customer-driven small solar resources over the next 15 years. This additional solar generation along with other resource choices should position us well for long-term compliance with greenhouse gas reductions. While our Resource Plan contemplates additional utility-scale solar being deployed in 2024 and beyond, we believe it is a reasonable policy choice to advance 100 MW of that target and deploy the Geronimo Solar Project at this time.

Furthermore, the Geronimo Solar PPA positions us to address known long-term changes to the NSP System beyond 2024. These changes will result in the Company needing to replace or extend the operating lives of nearly 75 percent of the energy producing resources on the NSP System over the next 20 years.

Q. PLEASE EXPLAIN THE ITC QUALIFICATION BENEFIT OF THE GERONIMO SOLAR PPA.

A. The Geronimo Solar Project is dependent upon obtaining the 30 percent ITC to offset a significant proportion of the costs of the project. The 30 percent ITC applies to any project that goes into service by the end of 2016. The ITC automatically reduces to 10 percent for projects that go into service after 2016, and we are not assuming that the higher ITC rate will be renewed to prevent the imminent reduction in this significant generation subsidy.

Our customers are increasingly interested in new energy choices, and state and federal policies are promoting solar as a way to reduce GHG emissions and support local economic development. Thus, there is a benefit in pursuing additional solar generation at this time to capture the higher ITC generation subsidy and realize the other benefits of solar generation on our integrated system.

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)

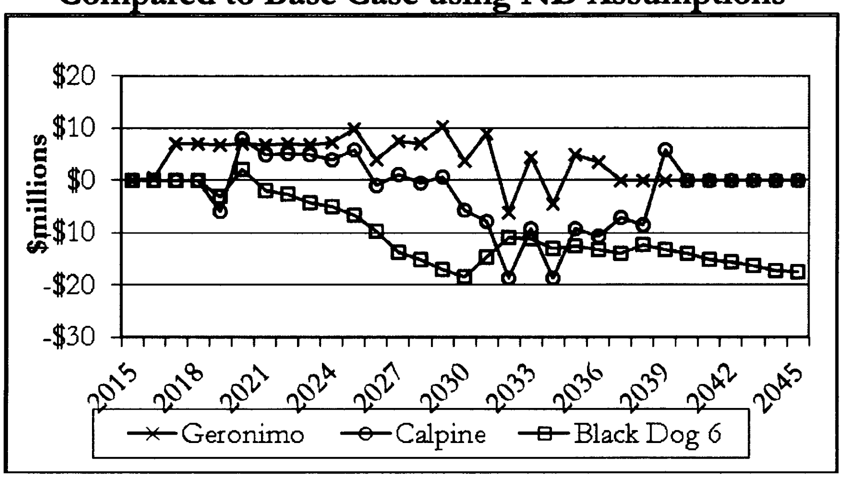
Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base case using ND Assumptions	$0	$0	$0	$0	$0	$0
Add Geronimo Solar PPA	$62	$71	$76	$44	$49	$35
Add Calpine Mankato CC PPA	($11)	($22)	$10	($40)	($74)	($27)
Add Black Dog 6 CT	($112)	($118)	($101)	($127)	($132)	($103)
Add Geronimo & 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, including 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 7 below shows the aggregate impact of the Geronimo Solar PPA, the Calpine Project PPA, and Black Dog Unit 6.

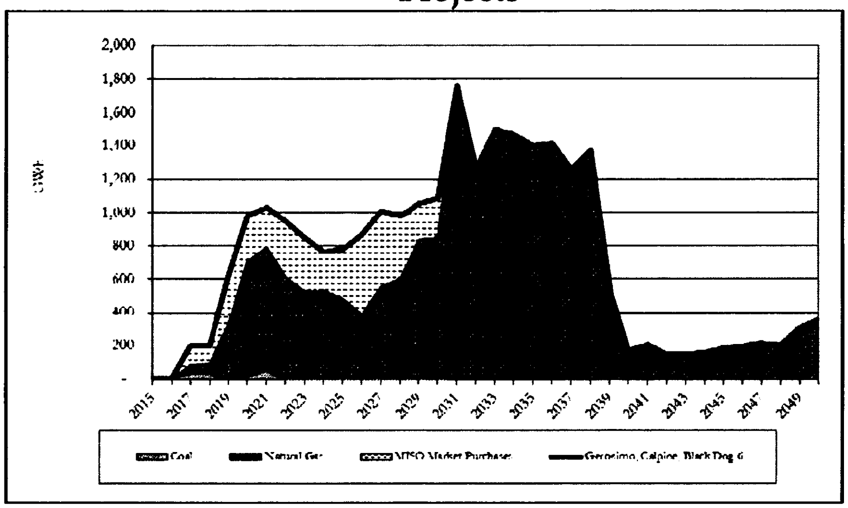
Figure 7:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions



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 8 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, and coal generation has a net output increase of 1 percent over the analysis period (2014-2053).

Figure 8:
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.

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 AURORA DISTRIBUTED SOLAR, LLC FOR UP TO 100 MW OF SOLAR 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 13th day of February, 2015.

Cynthia D. H

~~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
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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.